143. The placement of OCAPS within ETI's service area in close proximity to the industrial load center in Southeast Texas will enhance reliability by reducing dependence on existing transmission infrastructure, reducing transmission losses, and providing reactive power needed to serve the types of load in the area.

144. OCAPS will help maintain transmission system inertia and dynamic reactive support within the region and provide critical in-region capacity to help maintain service during major storms and facilitate more rapid system restoration following such storms.

145. Sabine 1, 3, and 4 have been regularly committed by MISO to address voltage and local reliability issues.

146. With the deactivation of Sabine 1, 3 and 4, the addition of OCAPS to replace them is necessary to avoid negative impacts on service reliability in ETI's Eastern Region.

147. The ability of OCAPS to access natural gas stored at ETI's Spindletop facility provides an additional reliability benefit in times of constrained natural gas supply.

148. ETI and its customers will benefit from the proposed CCN amendment because OCAPS will enhance reliability by: (1) replacing aging, less reliable legacy generation, (2) providing the most efficient generation in MISO South, and (3) having the ability to operate in severe weather conditions, including extreme cold and extreme heat.

Necessity for Service Accommodation, Convenience, or Safety of the Public

149. The requested amendment to ETI's CCN to construct, own, and operate OCAPS, excluding the hydrogen component, is necessary for the service, accommodation, convenience, or safety of the public.

Effect of CCN Amendment on the Renewable Resources Goal Established by PURA § 39.904(a)

150. Texas has met the goal of establishing 10,000 MW of installed renewable capacity for the state by January 1, 2025, as set out in PURA § 39.904(a).

151. OCAPS would not affect Texas's ability to reach its renewable energy goal.

Texas Parks and Wildlife Department

152. On September 16, 2021, ETI provided the Environmental Assessment in this project to the Texas Parks and Wildlife Department (TPWD).

153. On November 9, 2021, TPWD filed comments and recommendations in this proceeding. TPWD did not seek to intervene.

154. The mitigation measures set out in Exhibit DS-SD-1 to Deborah Saxton's supplemental direct testimony adequately address TPWD concerns.

B. Conclusions of Law

1. The Commission has jurisdiction over this matter in accordance with Public Utility Regulatory Act (PURA) sections 14.001, 37.051(a), 37.053, 37.056, 37.058(b), and 39.452(j).

2. SOAH has jurisdiction over this proceeding, including the preparation of a proposal for decision with findings of fact and conclusions of law, under PURA section 14.053 and Texas Government Code section 2003.049.

3. Because the proposed facility does not yet exist and would not be built until regulatory approvals have been obtained, the 366-day case-processing timeline set forth in PURA section 37.058(d) applies to this proceeding.

4. This case was processed in accordance with the requirements of PURA, the Administrative Procedure Act, and Commission rules.

5. ETI provided notice of the application in accordance with PURA section 37.054 and 16 Texas Administrative Code (TAC) sections 22.52(a).

6. ETI is a public utility as that term is defined in PURA section 11.004(1) and an electric utility as that term is defined in PURA section 31.002(6).

7. ETI currently provides adequate service, but it has a need for additional service under PURA section 37.056(c)(1) through (2), in that it needs

additional capacity, energy, and reliability, which the proposed facility would help provide.

8. The requested CCN amendment would not adversely affect any electric utility serving the proximate area under PURA section 37.056(c)(3).

9. The requested CCN amendment would not adversely affect community values, recreational and park areas, or historical values under PURA section 37.056(c)(4)(A)-(C).

10. The requested CCN amendment would have a minimal adverse effect on aesthetic values and environmental integrity under PURA section 37.056(c)(4)(C)-(D).

11. The requested CCN amendment would result in the probable improvement of service and the probable lowering of cost to consumers in the area under PURA section 37.056(c)(4)(E).

12. The requested CCN amendment would not affect Texas's ability to reach the renewable energy goal established by PURA section 39.904(a) and considered under section 37.056(c)(4)(F) because that goal has already been met.

13. ETI's application, as modified by this Order, meets the applicable requirements of PURA sections 37.056, 37.058, and 39.452(j) regarding generation CCN amendments.

14. OCAPS is necessary for the service, accommodation, convenience, or safety of the public within the meaning of PURA section 37.056(a).

15. The Commission has authority to impose conditions on its CCN approval under PURA section 37.056(b)(2).

16. ETI's application should be approved subject to the conditions in Finding of Fact Nos. 111-114.

C. Proposed Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the

Commission issues the following order:

1. The Commission adopts the proposal for decision, including findings of fact and conclusions of law.

2. The Commission amends Entergy Texas, Inc.'s certificate of convenience and necessity number 30076 to include the construction, ownership and operation of the Orange County Advanced Power Station, an approximate 1,125 MW combined-cycle combustion turbine generation unit to be located at the existing Sabine Power Station in Bridge City, subject to the conditions described in Finding of Fact Nos. 111-114.

3. Entergy Texas, Inc. shall exhaust all legal remedies to ensure consumers receive the benefits of the heat rate guaranteed under the Engineering, Procurement, and Construction agreement if the plant does not perform as expected, and any liquidated damages relating thereto shall inure to the benefit of the customers.

4. ETI shall follow the mitigation measures referenced in Finding of Fact No. 154.

5. The Commission limits the authority granted by this Order to a period of seven years from the date the Order is signed unless the Orange County Advanced Power Station is commercially operational before that time.

6. All other motions, requests for entry of specific findings of fact or conclusions of law, and any other requests for general or specific relief, if not expressly granted herein, are denied

SIGNED SEPTEMBER 26, 2022.

Christiaan Siano,
Presiding Administrative Law Judge

Megan Johnson,
Administrative Law Judge

ORIGINAL

CMM
ARW

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR AUTHORITY TO IMPLEMENT REVISED STEAM PRODUCTION DEPRECIATION ACCRUAL RATES APPLICABLE TO ITS ROCKPORT UNIT 1 TO REFLECT A CHANGE IN THE EXPECTED SERVICE LIFE OF THE TANNERS CREEK PLANT AND APPROVAL OF BASIC RATES ADJUSTMENT THROUGH A DEPRECIATION CREDIT	)	CAUSE NO. 44555 APPROVED: MAY 20 2015

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

On October 31, 2014, Indiana Michigan Power Company ("I&M", "Company" or "Petitioner") filed its Verified Petition and supporting testimony with the Indiana Utility Regulatory Commission ("Commission") for accounting authority to implement revised depreciation accrual rates applicable to its Rockport Plant Unit 1 to reflect a change in the expected service life of the Tanners Creek Plant and for approval of a downward adjustment to I&M's basic rates for retail electric service through a depreciation credit rider ("Depreciation Credit").

On February 4, 2015, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony of Duane P. Jasheway, Utility Analyst in the OUCC's Electric Division.

The Commission conducted a public hearing at 10:00 a.m. on March 4, 2015, in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. I&M and the OUCC appeared and participated at the hearing. No members of the general public attended the hearing.

Based upon applicable law and evidence presented, the Commission finds:

1. **Notice and Jurisdiction.** Notices of the hearing in this Cause were given and published as required by law. Proofs of publication of the notices are contained in the official files of the Commission. I&M is a public utility as defined in Indiana Code § 8-1-2-1(a). Ind. Code § 8-1-2-19 ("Section 19") authorizes the Commission to "ascertain and determine the proper and adequate rates of depreciation of several classes of property of each public utility." Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes in I&M's schedules of rates and charges. Therefore, the Commission has jurisdiction over I&M and the subject matter of this Cause.

2. **I&M's Characteristics.** I&M, a wholly-owned subsidiary of American Electric Power ("AEP"), is a corporation organized and existing under the laws of the State of Indiana, with its principal office at Indiana Michigan Power Center, Fort Wayne, Indiana. I&M is engaged in,

among other things, rendering electric service in the States of Indiana and Michigan. In Indiana, I&M provides retail electric service to approximately 458,000 customers.

3. **Relief Requested.** I&M is requesting accounting authority to implement revised steam plant depreciation accrual rates for Rockport Plant Unit 1 to reflect the change in the expected life of I&M's Tanners Creek Plant. More specifically, I&M seeks approval of revised steam production depreciation accrual rates for Rockport Plant Unit 1 over its expected remaining life based on a depreciation study using electric utility plant in service on December 31, 2013 ("December 2013 Depreciation Study"). The depreciation rates are intended to provide recovery of invested capital, cost of removal, and credit for salvage for both Rockport Plant Unit 1 and the Tanners Creek Plant. The requested revised depreciation accrual rates result in a reduction in I&M's total annual depreciation expense. I&M requests authority to reflect this reduction in depreciation expense as a credit to its customers' bills through the Depreciation Credit.

4. **I&M Direct Evidence.** Paul Chodak III, President and Chief Operating Officer of I&M, discussed the closure of the Tanners Creek Plant as of June 1, 2015, due to increasing environmental regulations. Mr. Chodak testified concerning the environmental challenges facing I&M, and I&M's strategy for complying with environmental regulations. Mr. Chodak testified that I&M's decision to close Tanners Creek Units 1, 2 and 3, as also outlined in Cause Nos. 44075 and 44422, remains the right choice because further investment is not economically warranted. Mr. Chodak stated that it is more efficient and consistent with the progress of the utility industry to comply with environmental mandates by closing these three units and to use other resources to meet I&M's customers' ongoing needs for electricity.

Mr. Chodak further explained I&M's decision to close Tanners Creek Unit 4. Mr. Chodak stated that I&M decided to close the coal-fueled Tanners Creek Unit 4 rather than refuel it to operate on natural gas based on an analysis of resource needs and environmental compliance costs as part of I&M's disciplined approach to capital investment. Further, based on relatively flat electricity demand and I&M's ability to meet the needs of its customers without the Tanners Creek Plant, I&M determined that the cost of refueling Tanners Creek Unit 4 is not an economic means of compliance with the Environmental Protection Agency's ("EPA") Mercury and Air Toxics Standard ("MATS Rule") and other pending or anticipated federal mandates. Last, Mr. Chodak stated the age of Tanners Creek Unit 4, combined with new environmental mandates, energy efficiency programs, and low market prices further combined to make closure the best decision I&M could make for its customers.

Mr. Chodak also described I&M's plans for the Rockport Plant. Mr. Chodak stated that the two units of the Rockport Plant provide relatively low cost, coal-fired energy to I&M's customers and are strong performers in I&M's generating fleet. He said I&M's current plans for the Rockport Plant include moving forward with Dry Sorbent Injection systems and Selective Catalytic Reduction technology. However, he explained I&M recognizes that there are still risks and uncertainties facing coal-fired power plants and I&M is working hard on managing the policies and regulations creating the risks and on the operational changes needed to manage those risks.

Mr. Chodak testified that the Tanners Creek Plant closure will be prior to the end of the units' current depreciable service lives and therefore there are plant reserve balances remaining to be depreciated. Mr. Chodak explained that I&M seeks approval of revised depreciation rates that will allow I&M to combine the undepreciated reserve balances of the Tanners Creek Plant with the depreciation reserve balances of Rockport Plant Unit 1. Mr. Chodak stated that revising I&M's

depreciation rates will benefit customers by gradually recovering the remaining balances over the depreciable life of Rockport Plant Unit 1 rather than seeking immediate recovery of the investment in rates charged to customers. According to Mr. Chodak, approval of I&M's request will permit I&M to recover its investment in the Tanners Creek Plant without the need to increase the current rates for service paid by I&M's customers.

Mr. Chodak stated that consistent with the Settlement Agreement approved by the Commission in Cause No. 43774 PJM 4, I&M is proposing that if I&M's request is approved and I&M receives a reduction to its Indiana jurisdictional depreciation expense, the expense reduction will be implemented in rates when the depreciation rate change is effective or as otherwise approved by the Commission. More specifically, I&M proposes to submit a Depreciation Credit tariff sheet to flow through the reduction in depreciation expense to customers in the form of a credit to their monthly bill.

Finally, Mr. Chodak explained the importance of I&M's request to revise the depreciation rates applicable to its steam generating plants. Mr. Chodak testified that the December 2013 Depreciation Study shows that changes in circumstances and the passage of time have caused I&M's existing steam generating depreciation rates to be in need of revision. Mr. Chodak stated that the proposed depreciation rate changes are reasonable and necessary to provide I&M with a more appropriate and accurate depreciation accrual based upon current regulatory circumstances, which better matches the cost of I&M's plant in service with the periods expected to benefit.

David A. Davis, Manager-Property Accounting Policy and Research for American Electric Power Service Corporation ("AEPSC"), provided the methodology and calculations used to determine the updated depreciation accrual rates for Tanners Creek Plant and Rockport Plant Unit 1 before and after the retirement of the Tanners Creek Plant. As shown in Table 1 (before the retirement of Tanners Creek Plant), Mr. Davis compared I&M's existing depreciation rates and accruals to rates and accruals based upon the December 2013 Depreciation Study.

Table 1 - Composite Rates and Accruals Based on Plant In-Service at December 31, 2013

	Existing		Study		Difference
	Rates	Accruals	Rates	Accruals	
Steam Production Plant					
Rockport Unit 1	2.09%	$14,199,012	1.38%	$9,394,734	($4,804,278)
Tanners Creek Plant	3.74%	$23,729,805	1.38%	$8,764,043	($14,965,762)
Total Rockport Unit 1 and Tanners Creek Plant	2.88%	$37,928,817	1.38%	$18,158,777	($19,770,040)

Next, Mr. Davis calculated depreciation rates for Rockport Plant Unit 1 after the retirement of the Tanners Creek Plant and compared those rates and accruals using existing and study rates. Mr. Davis testified that I&M requests that the Commission approve the revised depreciation rates for Rockport Plant Unit 1 after the retirement of Tanners Creek. The revised steam plant depreciation rates are provided in the December 2013 Depreciation Study, Attachment DAD-2, and shown on Table 2.

Table 2 - Composite Rates and Accruals Based on Plant In-Service at December 31, 2013 beginning June 1, 2015

Rockport Unit 1

		Existing		Study		Difference
		Rates	Accruals	Rates	Accruals	Amount
311.0	Structures & Improvements	1.93%	1,842,037	2.17%	2,073,411	231,374
312.0	Boiler Plant Equipment	2.08%	8,792,770	2.86%	12,102,517	3,309,747
314.0	Turbogenerator Units	2.35%	2,113,798	2.77%	2,493,997	380,199
315.0	Accessory Electrical Equipment	1.92%	1,111,925	1.97%	1,139,333	27,408
316.0	Miscellaneous Power Plant Equip.	2.28%	338,482	2.35%	349,525	11,043
	Total Rockport Unit 1	2.09%	14,199,012	2.67%	18,158,783	3,959,771

(1) The investment in Rockport Plant Unit 1 excludes the cost associated with the activated carbon injection system.

As explained by Mr. Davis, when compared to current rates and accruals, the recommended depreciation study's steam plant depreciation rate changes for Rockport Plant Unit 1 and Tanners Creek Plant result in an annual amount of depreciation expense equal to $18,158,777 based on plant in service at December 31, 2013, which is a decrease in annual depreciation expense. The overall decrease in depreciation expense is due to depreciation rates being calculated using the combined values for Rockport Plant Unit 1 and Tanners Creek and recovering these amounts over the remaining life of Rockport Plant Unit 1. The Table 1 and Table 2 depreciation study rate calculations provide a level amount of depreciation expense before and after the Tanners Creek Plant retirement ($18,158,777 on Table 1, and $18,158,783 on Table 2). The Table 2 calculation of depreciation rates results in a $3,959,771 increase in Rockport Plant Unit 1's depreciation expense after the Tanners Creek Plant's retirement (see Table 2, above) while maintaining the same overall annual depreciation accrual. The depreciation study accruals and rates allow for recovery of the remaining value of both plants including final demolition costs over the remaining life of Rockport Plant Unit 1.

Lastly, Mr. Davis sponsored Attachment DAD-5 which provides a calculation of the $20,586,083 Total Company ($13,309,971 Indiana jurisdictional based on the production demand allocation factor from Cause No. 44075) decrease in depreciation expense due to the recommended change in depreciation rates when compared to the amount included in the revenue requirement used to establish I&M's basic customer rates in Cause No. 44075.

Nancy A. Heimberger, Principal Regulatory Consultant in Regulated Pricing and Analysis at AEPSC, supported I&M's calculation of the Depreciation Credit factors and provided the resulting rate impact on I&M's Indiana customers. Ms. Heimberger testified the Depreciation Credit factors were calculated by taking the Indiana jurisdictional depreciation credit of $13,309,971 from

Attachment DAD-5 and allocating it across the classes using a demand allocator. Next, Ms. Heimberger determined the factors by using the same kWh billing determinants used to develop I&M's basic rates in Cause No. 44075. Ms. Heimberger stated that the Depreciation Credit will result in an overall bill decrease of approximately $1.24 or 1.3% for a residential customer using 1,000 kWh per month.

Ms. Heimberger further testified that upon Commission approval, I&M will implement the Depreciation Credit rider effective on a service rendered basis with the retirement of the Tanners Creek Plant. The Depreciation Credit will be in effect until a revised depreciation expense is reflected in I&M's basic rates.

5. **OUCC's Evidence.** Mr. Jasheway discussed I&M's request to change its steam production depreciation rates. Mr. Jasheway noted that a request to change depreciation rates should be evaluated on a case-by-case basis and that considering the specific circumstances in this particular Cause, the OUCC has no objection to I&M adjusting its depreciation rates outside of a rate proceeding. Mr. Jasheway testified that I&M's decision to include the remaining Tanners Creek Plant cost in accumulated depreciation and recover the same over the remaining 30 year life of Rockport Plant Unit 1 provides benefits to I&M's customers and allows I&M to recoup the remaining cost for the Tanners Creek Plant.

6. **Commission Discussion and Findings.** I&M seeks Commission approval of, and authority to implement, revised steam plant depreciation accounting rates applicable to its electric utility plant in service. Section 19 provides that the Commission shall ascertain and determine the proper and adequate rates of depreciation of each public utility. Significant changes in a utility's system can create conditions which, as presented by I&M in this proceeding, drive material changes in the proper and adequate rates of depreciation to be included in retail rates. Accordingly, because the resulting proposed depreciation expense is less than what is currently reflected in its base rates, I&M also proposed to implement a Depreciation Credit to customer bills.

I&M's current depreciation rates for its electric utility plant were established by the Commission in its February 13, 2013 Order in Cause No. 44075 ("44075 Order"), I&M's most recent general basic rate case, and were based on a depreciation study using plant balances as of December 31, 2010. The depreciation study from Cause No. 44075 used a 2015 retirement date for Tanners Creek Units 1-3 and a 2030 retirement date for Tanners Creek Unit 4. Following the 44075 Order, I&M made the decision to retire Tanners Creek Unit 4 as of June 1, 2015, considering the costs of refueling, the current demand for electricity, the capacity markets in which I&M operates, and existing and potential federal environmental mandates.

The December 2013 Depreciation Study and the revised depreciation accrual rates proposed by I&M reflect the change in the expected service life of Tanners Creek Plant and allow I&M to recover the remaining net book value of the Tanners Creek Plant (at retirement) over the expected remaining life of Rockport Plant Unit 1. The depreciation rates determined by the December 2013 Depreciation Study will provide recovery of invested capital, cost of removal, and credit for salvage for both Rockport Plant Unit 1 and the Tanners Creek Plant. The record reflects that including the remaining Tanners Creek cost in accumulated depreciation and recovering the cost over the remaining life of Rockport Plant Unit 1 spreads the cost over 30 years, benefitting customers by using an extended recovery period and permitting I&M to recover the remaining investment in Tanners Creek. Further, the revised depreciation rates will better match the cost of I&M's steam plant in service with the estimated remaining life of these assets, which is consistent with FERC accounting rules. We note the OUCC recommended approval of I&M's requested revised steam production depreciation accrual rates.

The resulting depreciation expense based on the revised steam plant depreciation accrual rates will be lower than the current depreciation expense reflected in its base rates. I&M proposed that this reduction be recognized as an adjustment to I&M's rate schedules through its proposed Depreciation Credit. The bill of a typical residential customer using 1000 kWh per month will decrease by $1.24 or 1.3% once the Depreciation Credit is implemented.

Based on the specific evidence presented in this Cause, we find that the proposed steam plant depreciation accrual rate changes are appropriate. Accordingly, we find that I&M's revised steam plant depreciation accrual rates applicable to I&M's Rockport Plant Unit 1 as set forth in the December 2013 Depreciation Study should be approved and I&M is authorized to place such rates into effect for accounting purposes upon retirement of the Tanners Creek Plant. The Commission also finds I&M's proposed Depreciation Credit is reasonable and should be approved. The Depreciation Credit factors will be implemented upon approval by the Electricity Division, and the factors will remain in effect until further order of the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION THAT:

1. I&M is hereby authorized to place into effect for accrual accounting purposes the revised steam plant depreciation accrual rates applicable to I&M's Rockport Plant Unit 1 as provided in the December 2013 Depreciation Study, upon retirement of the Tanners Creek Plant.

2. Petitioner's proposed Depreciation Credit is approved.

3. Petitioner shall file with the Commission's Electricity Division, prior to placing in effect the Depreciation Credit approved herein, a revised tariff page as shown in Attachment NAH-2.

4. This Order shall be effective on and after the date of its approval.

STEPHAN, MAYS-MEDLEY, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED: MAY 20 2015

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission

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 AND THE ELECTRIC SERVICE RULES, REGULATIONS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	Cause No. PUD 201700151 ORDER NO. 672864

HEARINGS: October 30-31, November 1-3 and 6-9, 2017, in Room 301, 2101 N. Lincoln Blvd., Oklahoma City, Oklahoma 73105 *before* Mary Candler, Administrative Law Judge

January 4, 2018, Hearing on Motions for Oral Argument and Exceptions to the Report of the Administrative Law Judge *before* the Commission in Room 301

APPEARANCES:
Jack P. Fite, Joann S. Worthington, and Kendall Parrish, Attorneys *representing* Public Service Company of Oklahoma
Dara Derryberry, Katy Boren, Jared Haines, Chase Snodgrass, Assistant Attorneys General, *representing* the Office of the Attorney General, State of Oklahoma
Judith L. Johnson and Natasha Scott, Deputy General Counsels, Michael Velez, Lauren Hensley, and Olivia Waldkoetter, Assistant General Counsels, *representing* the Public Utility Division, Oklahoma Corporation Commission
Thomas P. Schroedter, Attorney, *representing* Oklahoma Industrial Energy Consumers
Deborah Thompson, Attorney, *representing* AARP
Rick D. Chamberlain, Attorney, *representing*, Wal-Mart Stores East LP and Sam's East, Inc.
Marc Edwards, James A. Roth, and C. Eric Davis, Attorneys, *representing* Oklahoma Hospital Association
Matthew Dunne, General Attorney, *representing* United States Department of Defense and all Other Federal Executive Agencies

FINAL ORDER

BY THE COMMISSION:

The Corporation Commission of the State of Oklahoma ("Commission") being regularly in session and the undersigned Commissioners being present and participating, there comes on for consideration and action the Report and Recommendation of the Administrative Law Judge ("ALJ") for an order of the Commission.

I. PROCEDURAL HISTORY

The procedural history of this Cause through the date of the hearing held before the ALJ is contained in the Report and Recommendations of the Administrative Law Judge filed December 11, 2017 ("ALJ Report").

On December 18, 2017, the Public Utility Division ("PUD"), Public Service Company of Oklahoma ("PSO"), the Oklahoma Attorney General ("AG"), Oklahoma Industrial Energy Consumers (OIEC"), and the Oklahoma Hospital Association ("OHA") each filed Exceptions to the ALJ Report and filed motions for oral argument.

On December 19, 2017, PSO filed a Motion for Oral Argument and Notice of Hearing.

On December 21, 2017, the Commission issued Order No. 671356, granting the Motion to Associate Counsel filed herein by PSO related to Gerardo Noel Huerta, a member of the State Bar of Texas.

On December 22, 2017, PSO filed a Response to OIEC, AG and OHA's Exceptions to the ALJ Report; OIEC filed a Response to the Exceptions of PSO; the United States Department of Defense and all other Federal Executive Agencies ("DOD/FEA") filed a Response to Exceptions to the ALJ Report; and AARP filed a Response to the Exceptions to the ALJ Report.

On January 4, 2018, the Commission granted the Motions for Oral Argument and proceeded to hear the exceptions.

II. SUMMARY OF EVIDENCE

The summary of evidence is contained in the ALJ Report.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

THE COMMISSION FINDS that it is vested with jurisdiction, pursuant to Article IX, Section 18, of the Oklahoma Constitution, 17 O.S. §§ 151 *et seq.*, and the rules of the Commission.

THE COMMISSION FURTHER FINDS that notice of these proceedings was proper and was given as required by law and the orders of the Commission.

THE COMMISSION FURTHER FINDS that in the exercise of its legislative, judicial and executive powers it is required to reach its own conclusions based upon the evidence before it and that it may adopt, reject, restrict, or expand any or all findings and recommendations of the ALJ. *State ex rel. Cartwright v. Oklahoma Natural Gas Co. and Oklahoma Corporation*

Commission, 1982 OK 11, ¶8, 640 P.2d 1341, 1343.

Based upon a full review and evaluation of the ALJ Report and the record, and having heard the arguments of counsel, the Commission hereby adopts and incorporates by reference the recommendations set forth in the ALJ Report appended hereto as Attachment 1, except as otherwise stated herein.

Motion to Strike (ALJ Report pp. 9-10, IV ¶¶ 3-4)

While the Commission generally agrees with the above-cited statements of the ALJ, the Commission clarifies that the statements should not be construed as prohibiting parties from making any reference at any time to any stipulations and settlement agreements adopted in the past by the Commission. Also, the Commission recognizes and cautions that parties who agreed to settlement provisions are expected to follow them, and that compliance with Commission orders is and will be required.

Northeastern Unit 4 (ALJ Report p. 18, ¶¶ 51-59)

THE COMMISSION FINDS, having considered the particular facts and circumstances in this Cause and emphasizing that evaluation of this type of issue must be done on a case-by-case basis, that the Commission agrees in part with the ALJ's recommendation that would authorize a return of the investment associated with Northeastern Unit 4 ("NE 4") but not a return on the remaining investment. In balancing the interests of ratepayers and shareholders, THE COMMISSION FINDS it appropriate under the circumstances presented here to authorize a return of the investment associated with NE 4 and recovery of the carrying cost on the remaining investment at the cost of debt allowed in this proceeding.

Cost of Capital: Capital Structure, Cost of Debt, Return on Equity & Rate of Return (ALJ Report pp. 20-22, ¶¶ 62-73)

The Commission agrees with the ALJ's recommendation on PSO's capital structure and cost of debt and adopts paragraphs 62 through 64 of the ALJ Report. In addition, the Commission agrees with the ALJ's analysis and recitals to the record as far as the issue of Return on Equity ("ROE") is concerned in this case, except for her ultimate conclusion. Therefore, the Commission adopts paragraphs 65 through 72, except for the last sentence of paragraph 72 where the ALJ recommends that the Commission adopt a 9.0 percent return on equity.

The Commission has reviewed all the written and oral testimony of the expert witnesses offered in this Cause, including all models utilized by each ROE witness, and has given full consideration to the oral argument presented on the issue. After such review, the Commission finds that the appropriate ROE for PSO going forward should be 9.3 percent. The Commission further finds that a 9.3 percent return on equity meets all the necessary elements set forth in the *Hope* case (*Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)) as listed by the ALJ in her report in paragraph 65. A 9.3 percent ROE will give PSO the opportunity to earn a fair return on its investment, it will allow PSO a return similar to returns on other similarly risky investments, it will provide confidence in the financial integrity of the company, and will allow the company to attract capital. Finally, the 9.3 percent ROE balances the interests of both the investor and the consumer.

Based on the above, the Commission finds that PSO's overall rate of return that results from the capital structure and cost of capital determined above is 6.88% rather than the 6.73% overall rate of return set forth in paragraph 73 of the ALJ Report, as is shown below.

Description	Capital Ratio	Cost Rate	Weighted Average Cost
Long Term Debt	51.49%	4.60%	2.37%
Common Equity	48.51%	9.30%	4.51%
Total Capital	100%		6.88%

SPP Fees and Expenses (ALJ Report p. 25, ¶¶ 91 and 92)

THE COMMISSION FINDS that the recommendation of the ALJ to disallow SPP fees and expenses requested by PSO [SPP Schedule 9 NITS (Network Integration Transmission Service) in the amount of $13,994,625] as addressed by the ALJ at Paragraphs 91 and 92 of the ALJ Report should not be adopted.

In her recommendation that such expenses should not be allowed, the ALJ cited portions of testimony in which it was established the SPP fees and expenses were not effective within the test year or the six-month post-test year period. In this instance, the amount of the SPP fees and expenses at issue were known and measurable within the applicable test year plus six-months post-test year period. The establishment of the obligation of PSO to pay those fees and expenses occurred during the applicable test year plus six-months post-test year period when the SPP established its formula rates in May of 2017 which included the SPP Schedule 9 NITS charges at issue. This was one month before the end of the six-months post-test year period, which ended

June 30, 2017. The noted expense was to become effective on July 1, 2017, which was one day after the end of the six-months post-test year period. (Jason Chaplin, Resp. Test. 10:11-14 Sept 21, 2017)

The statute relied upon by various parties arguing the position expenses should not be allowed because of being outside the six-months post-test year period is 17 O.S. § 284 - *Application to Change Rates and Charges - Effect Given to Known and Measurable Changes* - which states:

> In its review and examination of an application by a utility to change its rates and charges . . . 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. (emphasis added)

As shown by the emphasized word "shall," this statute *requires* all known and measurable changes that occur or are reasonably certain to occur within the test year or the six-month post-test year period be given effect in establishing new rates for a public utility. However, that language does not *limit* consideration by the Commission to the time period as was asserted. The Commission has reviewed this issue in previous causes and determined it has the power to consider known and measurable adjustments past the six-months post-test year period as was detailed at pages 21 and 22 of PSO's exceptions. (*See* Order No. 492407 in Cause No. PUD 200300076 and Order No. 545168 in Cause No. PUD 200600285)

The ALJ accepted the argument that since the payment obligation was not *effective* until one day after the end of the six-months post-test year period that the expense did not *occur* within that time and therefore, is not eligible to be included in establishing rates. Despite the fact that the expense was not effective until July 1, 2017, one day after the end of the six-months post-test year period, the expense *did* occur in the six-months post-test year period because it was known and measurable and the FERC approved tariff was filed during that time period. Either way, this expense is an actual expense borne by PSO, is known and measurable, and should be allowed in the rates to be established by the order to be issued in this Cause.

Depreciation (ALJ Report pp. 28-29, ¶¶ 104-110)

The Commission does not adopt paragraph 108 of the ALJ Report with respect to net salvage, and would adopt the position of PUD witness Carolyn Weber. Further, paragraph 109 of the ALJ Report should read as follows: THE COMMISSION FURTHER FINDS that, based upon the record of this Cause the service lives recommended by the Attorney General are adopted.

Federal Tax Legislation (ALJ Report pp. 34-35, ¶¶ 134-138)

In her report, the ALJ appropriately recognized the Commission's duty and authority in setting rates. The ALJ also recognized the existence of federal tax reform efforts underway at the time of the ALJ hearing. As set forth in her report, this issue was raised after questions by Commissioner Anthony to OIEC witness Mark Garrett and PSO witness Randy Hamlett. Accordingly and consistent with the ALJ's recommendation insofar as it recommends some action be taken, the Commission takes judicial notice of the Tax Cuts and Jobs Act, P.L. 115-97, enacted December 22, 2017, by the federal government reducing the federal corporate income tax rate to 21 percent of taxable income beginning January 1, 2018. Further, the Commission takes judicial notice of Commission Order No. 671981 in which the Commission on January 9, 2018, ordered PSO, in part, to:

> [R]ecord a deferred liability beginning on [January 9, 2018,] to reflect the reduced federal corporate tax rate to 21 percent and the associated savings in excess ADIT and any other tax implications of the Act on an interim basis subject to refund until utility rates are adjusted to reflect the federal tax savings through ... a final order in pending rate case PUD 201700151...[and that] the amounts of any refunds determined to be owed to customers shall accrue interest at a rate equivalent to PSO's cost of capital as recognized in Order No. 658529 issued in Cause No. PUD 201500208 until issuance of a final order in PSO's pending rate case in Cause No. PUD 201700151.... .

Order No. 671981, p. 4.

THE COMMISSION FINDS that PSO shall immediately reduce its rates in the amount necessary to reflect the lower federal corporate tax rate of 21 percent, distributed across rate classes in proportion to their share of the revenue requirement approved in this proceeding. THE COMMISSION FURTHER FINDS that all other tax savings resulting from P.L. 115-97, including the savings from the time period of January 9, 2018, through the date of this Order, and including savings through amortization of "excess" accumulated deferred taxes ("ADIT"), shall continue to be recorded as a deferred liability subject to refund with interest at the cost of capital pursuant to the provisions of Order No. 671981. The mechanism for flowing refunds back to customers for these tax savings and the consideration of all tax impacts of P.L. 115-97 shall be addressed as set forth in Order 671981 through PSO's next base rate case, or in a separately-filed proceeding, or through a final order in Cause No. PUD 201700572.

ORDER

IT IS THEREFORE THE ORDER OF THE CORPORATION COMMISSION OF OKLAHOMA that the ALJ Report appended hereto as Attachment 1, subject to and as amended or superseded by the modifications detailed hereinabove, is hereby adopted and incorporated herein as if fully set forth, as the order of the Commission.

IT IS FURTHER ORDERED that PSO shall, within three (3) business days of entry of this Order, file an accounting exhibit reflecting the terms of this Order.

IT IS FURTHER ORDERED that PSO shall, within thirty (30) days after the date of this Order, submit to the Director of the Public Utility Division tariffs consistent with the findings set forth herein, and that the rates, charges, and tariffs shall be effective with the first regular billing cycle after such tariffs are approved by the Director of the Public Utility Division.

OKLAHOMA CORPORATION COMMISSION

Dana L. Murphy
DANA L. MURPHY, Chairman

J. Todd Hiett
J. TODD HIETT, Vice Chairman

Bob Anthony
BOB ANTHONY, Commissioner

DONE AND PERFORMED this 31 day of January 2018.

BY ORDER OF THE COMMISSION:

Peggy Mitchell
PEGGY MITCHELL, Secretary

ATTACHMENT 1

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 AND THE ELECTRIC SERVICE RULES, REGULATIONS AND CONDITIONS OF SERVICE FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	CAUSE NO. [illegible] 2[illegible]70[illegible]51

FILED
DEC 11 2017
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

HEARING: October 30-31, November 1-3, and 6-9, 2017, in Courtroom 301
2101 North Lincoln Boulevard, Oklahoma City, Oklahoma 73105
Before Mary Candler, Administrative Law Judge

APPEARANCES:
Jack P. Fite, Joann S. Worthington, and Kendall W. Parrish, Attorneys *representing* Public Service Company of Oklahoma
Dara M. Derryberry, Deputy Attorney General, and Katy Evans Boren, Jared B. Haines and A. Chase Snodgrass, Assistant Attorneys General *representing* Office of Attorney General, State of Oklahoma
Judith L. Johnson and Natasha M. Scott, Deputy General Counsels, and Michael L. Velez, Lauren Hensley and Olivia Waldkoetter, Assistant General Counsels *representing* Public Utility Division, Oklahoma Corporation Commission
Thomas P. Schroedter, Attorney *representing* Oklahoma Industrial Energy Consumers
Deborah R. Thompson, Attorney *representing* AARP
Rick D. Chamberlain, Attorney *representing* Wal-Mart Stores East, LP and Sam's East, Inc.
Marc Edwards, James A. Roth, and C. Eric Davis, Attorneys *representing* Oklahoma Hospital Association
Matthew Dunne, Attorney *representing* United States Department of Defense and all other Federal Executive Agencies

REPORT AND RECOMMENDATION OF THE ADMINISTRATIVE LAW JUDGE

TABLE OF CONTENTS

This Cause comes before the Corporation Commission ("Commission") of the State of Oklahoma on the Application of Public Service Company of Oklahoma ("PSO" or "Company") seeking an adjustment to its rates and charges and the electric rules, regulations and conditions of electric service for electric service for the State of Oklahoma.

I. SUMMARY OF RECOMMENDATION

The Administrative Law Judge ("ALJ") respectfully submits this report and recommendation. In summary, PSO has requested a base rate revenue increase of $169,667,526. The ALJ recommends a base rate revenue increase of $81,220,570. Attachment "A" to this report is an accounting exhibit that reflects the ALJ's recommendation. The ALJ recommends the Company's proposed capital structure of 51.5 percent debt and 48.5 percent equity and a 4.6 percent cost of long term debt. The ALJ recommends 9.00 percent return on equity.

The ALJ recommends allowing recovery of Northeastern Unit 4 but not recovery on Northeastern Unit 4 since it is not being used to supply power to customers at this time. The ALJ recommends moving the System Reliability Rider and the Advanced Meter Infrastructure Rider from riders to base rates. The ALJ recommends that 50 percent of the annual incentive plan be excluded from rates while 100 percent of the long-term incentive plan be excluded from rates. The ALJ recommends that the Supplemental Executive Retirement Plan be 100 percent excluded from rates. Other recommendations are delineated within this document.

The ALJ recommends PSO's revenue distribution proposal that follows the revenue distribution recommendation from the final order in PSO's last rate case.

II. JURISDICTION AND NOTICE

PSO is an Oklahoma corporation authorized to do business in the State of Oklahoma. PSO is a public utility with plant, property, and other assets dedicated to the generation, production, transmission, distribution, and sale of electricity at wholesale and retail levels within the State of Oklahoma. The Commission has jurisdiction over this Cause by virtue of the provisions of Article IX, Section 18 of the Constitution of the State of Oklahoma, 17 O.S. §§ 151 et seq., and the Rules and Regulations of this Commission. Notice is proper in this Cause and complies with Order No. 667373 and the requirements of OAC 165:5-7-51.

III. PROCEDURAL HISTORY

1. On May 12, 2017, PSO filed its Notice of Intent, giving notice to the Commission of PSO's intent to file an Application seeking to modify the rates and charges for PSO's Oklahoma jurisdiction customers as well as amend PSO's Electric Service Rules, Regulations and Conditions of Service.

2. On May 16, 2017, the ALJ filed a Notice of Hearing for the Pre-Hearing Conference to be held on June 7, 2017.

3. On May 18, 2017, the Office of the Attorney General ("Attorney General") filed an Entry of Appearance for Dara M. Derryberry, Katy Evans Boren and Jared B. Haines.

4. On May 19, 2017, Thomas P. Schroedter filed an entry of appearance on behalf of Oklahoma Industrial Energy Consumers ("OIEC").

5. On June 7, 2017, the Pre-Hearing Conference was continued by agreement of the parties to June 15, 2017.

6. On June 15, 2017, the Pre-Hearing Conference was held and a Procedural Schedule for the processing of this Cause was recommended.

7. On June 20, 2017, Deborah R. Thompson filed an Entry of Appearance on behalf of AARP.

8. On June 30, 2017, PSO filed the Application, the Application Package (Schedules) Volume 1 and the Direct Testimony of: John O. Aaron, Pauline M. Ahern, Steven F. Baker, Andrew R. Carlin, Donald R. Dohrmann, Steven L. Fate, Brian J. Frantz, Randall W. Hamlett, Jennifer L. Jackson, Derek S. Lewellen, Thomas J. Meehan, Scott A. Ritz, C. Richard Ross, Tommy J. Slater, Wayman L. Smith, John J. Spanos, Michael J. Vilbert and David J. Wathen.

9. On July 7, 2017, a Notice of Hearing was filed setting a Pre-Hearing Conference for July 14, 2017.

10. On July 11, 2017, Rick D. Chamberlain filed an entry of appearance on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc.

11. On July 14, 2017, the ALJ's Preliminary Order was recommended.

12. On July 19, 2017, the Public Utility Division ("PUD") filed its Response Regarding Applicant's Compliance with the Minimum Filing Requirements.

13. On July 20, 2017, PSO filed Summaries of Direct Testimony of: John O. Aaron, Pauline M. Ahern, Steven F. Baker, Andrew R. Carlin, Donald R. Dohrmann, Steven L. Fate, Brian J. Frantz, Randall W. Hamlett, Jennifer L. Jackson, Derek S. Lewellen, Thomas J. Meehan, Scott A. Ritz, C. Richard Ross, Tommy J. Slater, Wayman L. Smith, John J. Spanos, Michael J. Vilbert and David J. Wathen.

14. On July 26, 2017, PSO filed an Errata to Work Paper G-06.

15. On August 24, 2017, the Commission issued Order No. 667373 Preliminary Order establishing the procedural schedule and notice requirements for the processing of this Cause.

16. On August 25, 2017, Matthew Dunne filed an Entry of Appearance on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA"). Also, on this date, DoD/FEA filed a Motion for Temporary Admission, For Admission Upon Filing of Certificate of Compliance, and For Waiver of Certain Requirements Pertaining to Out-of-State Attorneys along with a Notice of Hearing setting the Motion for Temporary Admission, For Admission Upon Filing of Certificate of Compliance, and For

Waiver of Certain Requirements Pertaining to Out-of-State Attorneys for hearing on August 31, 2017. A Proposed Order Admitting to Practice and Waiving Certain Requirements Pertaining to Out-of-State Attorneys was also filed.

17. On August 29, 2017, PSO filed an Errata to Schedule K-1; Schedule K-2A; Schedule K-2B; WPL-1; WPL-1-1; WPL-1-2; WPL-2; WPL-3; WPL-4; WPL-5; WPL-6; WPL-8; WPL-11

18. On August 31, 2017, the Motion for Temporary Admission, For Admission Upon Filing of Certificate of Compliance, and For Waiver of Certain Requirements Pertaining to Out-of-State Attorneys was heard and recommended.

19. On September 1, 2017, the Oklahoma Hospital Association ("OHA") filed an entry of appearance for Marc Edwards, James A. Roth and C. Eric Davis.

20. On September 14, 2017, PSO filed its Response to OIEC's Third Set of Data Requests.

21. On September 21, 2017, the following testimonies and exhibits were filed:

a. Responsive Testimony was filed by James B. Alexander, Todd F. Bohrmann, Edwin C. Farrar, Marlon F. Griffing, Ph.D. and William W. Dunkel on behalf of the Attorney General;

b. Responsive Testimony for David J. Garrett (Part I Risk and Return and Part II Depreciation) and Mark E. Garrett on behalf of OIEC. Also, Testimony and Exhibits of David C. Parcell were filed on behalf of OIEC and Wal-Mart;

c. Responsive Testimony for McKlein Aguirre, Kathy Champion, Jason C. Chaplin, Jeffrey Dunsworth, David Melvin, James E. Mitschke II, Kiran Patel, Geoffrey M. Rush, Jeremy K. Schwartz, Amy Taylor, Elbert D. Thomas, John Walkup, and Carolyn Jean Weber were filed on behalf of PUD. PUD also filed its Accounting Exhibit; and

d. Responsive Testimony for Maureen L. Reno was filed on behalf of DoD/FEA. Matthew Dunne filed a Certificate of Compliance on this date.

22. On September 22, 2017, Mark E. Garrett filed an Errata to his Responsive Testimony.

23. On September 25, 2017, the following Summaries of Responsive Testimony were filed: David C. Parcell and David J. Garrett on behalf of OIEC and Wal-Mart; Mark E. Garrett on behalf of OIEC; McKlein Aguirre, Kathy Champion, Jason C. Chaplin, Jeffrey Dunsworth, David Melvin, James E. Mitschke II, Kiran Patel, Geoffrey M. Rush, Jeremy K. Schwartz, Amy Taylor, Elbert D. Thomas, John Walkup, Carolyn Jean Weber on behalf of PUD; James B. Alexander, Todd F. Bohrmann, William W. Dunkel, Edwin C. Farrar, and Marlon F. Griffing, Ph.D., on behalf of the Attorney General; and Maureen L. Reno on behalf of DoD/FEA.

24. On September 26, 2017, David J. Garrett filed an Errata to his Responsive Testimony, Part II.

25. On September 27, 2017, William W. Dunkel filed an Errata to his Responsive Testimony. Marlon F. Griffing, Ph.D. also filed an Errata to his Responsive Testimony on this date.

26. Also on September 27, 2017, A. Chase Snodgrass filed an Entry of Appearance on behalf of the Attorney General.

27. On September 28, 2017, Kendall W. Parrish filed an Entry of Appearance on behalf of PSO.

28. On October 2, 2017, Marlon F. Griffing, Ph.D. filed a Second Errata to his Responsive Testimony.

29. On October 3, 2017, the following documents were filed:

a. Motion to Associate Counsel on behalf of PSO was filed along with a Notice of Hearing setting the Motion to Associate Counsel for hearing on October 5, 2017;

b. Jeremy K. Schwartz filed Responsive Testimony regarding Cost of Service and Rate Design on behalf of PUD as did Steve W. Chriss on behalf of Wal-Mart; and Larry Blank on behalf of DoD/FEA; and

c. Responsive Testimony of Scott Norwood and Mark E. Garrett on behalf of OIEC were filed. Also, Rate Design Testimony of James B. Alexander, Todd F. Bohrmann and Edwin C. Farrar on behalf of the Attorney General; Responsive Testimony of Maureen L. Reno, Responsive Testimony of Maureen L. Reno Redline version and Errata to the Responsive Testimony of Maureen L. Reno on behalf of DoD/FEA.

30. On October 5, 2017, two Supplemental Testimonies and the Summary of Supplemental Testimony of Maureen L. Reno on behalf of DoD/FEA were filed. Also on this date, Summaries of Testimony were filled by Larry Blank on behalf o DoD/FEA, Steve W. Chriss on behalf of Wal-Mart; Scott Norwood and Mark E. Garrett on behalf of OIEC; Todd F. Bohrmann, James B. Alexander and Edwin C. Farrar on behalf of the Attorney General.

31. Also on October 5, 2017, the Motion to Associate Counsel was heard and recommended.

32. On October 10, 2017, Statements of Position were filed by AARP and OHA.

33. On October 11, 2017, Rebuttal Testimony of James O. Aaron, Pauline M. Ahern, Steven F. Baker, Andrew R. Carlin, Steven L. Fate, Randall W. Hamlett, Thomas J. Meehan, John D. Quackenbush, Tommy J. Slater, John J. Spanos, Michael J. Vilbert, David J. Wathen were filed on behalf of PSO.

34. On October 12, 2017, the Commission issued Order No. 668994, Order Granting Motion for Temporary Admission, For Admission Upon Filing of Certificate of Compliance and For Waiver of Certain Requirements Pertaining to Out-of-State Attorneys. Also, Proof of Publication and Customer Notice was filed by PSO.

35. On October 13, 2017, Summaries of Rebuttal Testimony were filed by John O. Aaron, Pauline M. Ahern, Steven F. Baker, Andrew C. Carlin, Steven L. Fate, Randall W. Hamlett, Thomas J. Meehan, John D. Quackenbush, Tommy J. Slater, John J. Spanos, Michael J. Vilbert and David J. Wathen on behalf of PSO.

36. On October 16, 2017, Rebuttal Testimony regarding Cost of Service/Rate Design was filed by Steven L. Fate, Jennifer L. Jackson, Rebuttal Testimony of John O. Aaron and A. Naim Hakimi on behalf of PSO; Rebuttal Testimony by Jason C. Chaplin and Geoffrey M. Rush on behalf of PUD.

37. On October 18, 2017, Summaries of Rebuttal Testimony were filed by: Jason C. Chaplin and Geoffrey M. Rush on behalf of PUD and Summaries of Cost of Service/Rate Design Testimony of John O. Aaron, Steven L. Fate, A. Naim Hakimi and Jennifer L. Jackson on behalf of PSO.

38. On October 20, 2017, Maureen L. Reno on behalf of DoD/FEA filed clean and redline versions of her September 21, 2017, Responsive Testimony; clean and redline versions of her Supplemental Testimony filed on October 3, 2017; Errata to Supplemental Testimony and Second Errata to Responsive Testimony. Also on this date, OIEC filed a Motion to Strike Portions of Randall W. Hamlett's Rebuttal Testimony.

39. On October 23, 2017, a Notice of Hearing on the Motion to Strike Portions of Randall W. Hamlett's Rebuttal Testimony was filed setting the Motion to Strike Portions of Randall W. Hamlett's Rebuttal Testimony for hearing on October 26, 2017.

40. On October 24, 2017, Oral Surrebuttal Issues were filed by DoD/FEA, the Attorney General, PUD, Wal-Mart and OIEC. Also on this date, Exhibit Lists for PUD and Wal-Mart were filed.

41. On October 25, 2017, Exhibit Lists for OIEC, PSO, Attorney General, OHA and AARP were filed.

42. On October 26, 2017, the following documents were filed or hearings took place:

a. an Amended Rebuttal Testimony of Randall W. Hamlett on behalf of PSO was filed;

b. the Motion to Strike Portions of Randall W. Hamlett's Testimony was heard and recommended with instruction;

c. Affidavits of John O. Aaron, Pauline M. Ahern, Andrew R. Carlin, Steven L. Fate, A. Naim Hakimi, Randall W. Hamlett, Jennifer L. Jackson, Thomas J. Meehan, John D. Quackenbush, Tommy J. Slater, John J. Spanos, Michael J. Vilbert, and David J. Wathen were filed;

d. the Pre-Hearing Conference was held; and

e. Public Comments were also heard and the sign-in sheet was filed.

43. On October 27, 2017, Public Comments were filed.

44. On October 30, 2017, Exhibits No. 1-9 were filed. The Hearing on the Merits was heard and continued each day through November 9, 2017, at which time the ALJ took the matter under advisement.

45. On November 1, 2017, an Updated Exhibit MLR-1S ROE Comparison was filed as was Exhibit 10.

46. On November 2, 2017, a Public Comment Sign In Sheet was filed. Also, Exhibits No. 11-23 were filed.

47. On November 3, 2017, the following documents were filed:

a. Public Comment was filed;

b. Exhibits No. 24-58 were filed (excluding Exhibit No. 51);

c. An Affidavit of Steven F. Baker was filed;

d. PSO filed AEP-PSO Electric Utility Rate Increase 1 of 2 and 2 of 2; and

e. Exhibit 39 and Exhibit 51 were filed.

48. On November 6, 2017, Exhibits 59 and 60 were filed.

49. On November 7, 2017, Public Comment File EEI Briefing Book was filed. Exhibit 61 was also filed on this date.

50. On November 8, 2017, Public Sign-In Sheet was filed as well as Exhibits 62, 63 and 64.

51. On November 9, 2017, the Affidavit of Steve W. Chriss was filed, as was Exhibit 46A.

52. On November 13, 2017, Public Comment was filed.

53. On November 15, 2017, Public Comments were filed.

54. On November 20, 2017, the All Parties Issue Lists was filed.

55. Also on November 20, 2017, PSO filed the Supplemental Testimony Summary of Randall W. Hamlett. The Proposed Findings of Fact and Conclusions of Law were filed by PSO, OIEC, AARP, Attorney General, Wal-Mart, DoD/FEA, and PUD on this date.

56. On December 4, 2017, the Affidavit of Larry Blank was filed.

IV. MOTION TO STRIKE

On October 20, 2017, OIEC filed a Motion to Strike Portions of Randall W. Hamlet's Rebuttal Testimony ("Motion"). The Motion was heard at the Pre-Hearing Conference on October 26, 2017. OIEC's Motion requested the striking of portions of Mr. Hamlett's Rebuttal Testimony that cited a settlement agreement as precedential. OIEC argued that a settlement agreement in a prior case was cited as precedential and binding, notwithstanding the Settlement Agreement, which was signed by PSO and the other parties to the Agreement, expressly provided that nothing in the Agreement "shall constitute [] or be cited as precedent." Settlement Agreement, § 8(e), filed on June 17, 2014, in Cause No. PUD 201300217. According to the cited Settlement Agreement, the parties to the Settlement further agreed that the Commission's decision to enter an order consistent with the Settlement Agreement was binding only "as to the matters decided regarding the issues described in the [Settlement Agreement], but the decision [was] not to be binding with respect to similar issues that might arise in other proceedings." *Id.*

The Attorney General, AARP, Wal-Mart, and OHA supported OIEC's Motion to Strike and noted that this was a recurring issue. (Oct. 26, 2017, Excerpt Transcript of Pretrial Conference at KA7-10). At the hearing on the Motion, PSO agreed that the Motion to Strike should be granted. The ALJ recommended granting the motion with instruction. The ALJ directed PSO to file amended testimony that removed testimony that cited settlement agreement(s) as precedential. The ALJ also informed the parties that the issue would be addressed further in the ALJ report because it is an issue that re-occurs and should be addressed. (*Id.*, p. KA13). PSO filed Amended Testimony of Hamlett as directed.

Reliance on settlement agreements that have been approved by the Commission in which the parties to the agreement have agreed do not constitute precedent in other cases and that should not be cited as precedent in other cases will cause a chilling effect, deterring settlements in future proceedings. Therefore, it is the recommendation of the ALJ that the Commission finds and declares that parties shall not rely upon, and shall not file or elicit testimony that relies upon, provisions of settlement agreements that provide that they are not binding in other proceedings and are not to be cited as precedent, or that contain similar language, except where necessary to enforce the terms of the settlement agreement or to determine rights arising under the settlement agreement.

This issue came up several times throughout the Hearing on the Merits and involved not just one witness's testimony. A simple statement of recommendation of this Motion does not adequately address this issue in this Cause. Therefore, the ALJ is recommending broader language related to this issue in the below recommended Findings of Fact and Conclusions of Law.

V. SUMMARY OF THE EVIDENCE

Documents filed in this Cause are contained in the record kept by the Court Clerk of the Commission. Pre-filed testimony was filed of record and live testimony was offered at the Hearing on the Merits.. The entirety of the live testimony offered is contained in the transcripts of these proceedings. Summary of the testimony is set forth in Attachment "B" attached hereto and incorporated herein.

Exhibits:

Exhibits were admitted into evidence at the Hearings on the Merits and are filed of record in this Cause. The list of those Exhibits is set forth in Attachment "C" attached hereto and incorporated herein.

VI. FINDINGS OF FACT AND CONCLUSIONS OF LAW

After consideration of all evidence in this Cause, the ALJ recommends the Commission adopt the following Findings of Fact and Conclusions of Law. Such findings and conclusions are numbered sequentially for clarity. The ALJ's findings being with "The Commission" finds. There is no presumption on the part of the ALJ that she speaks for the Commission. The ALJ has used a format that she hopes can be easily used by the Commissioners, should there be a desire to use any of these Findings of Fact and Conclusions of Law, in a final order. Any subheadings used are also for clarity.

Jurisdiction and Notice

1. THE COMMISSION FINDS that PSO is an Oklahoma corporation authorized to do business in the State of Oklahoma. PSO is a public utility with plant, property, and other assets dedicated to the generation, production, transmission, distribution, and sale of electricity at wholesale and retail levels within the State of Oklahoma. The Commission has jurisdiction over this Cause by virtue of the provisions of Article IX, Section 18 of the Constitution of the State of Oklahoma, 17 O.S. §§ 151 *et seq.*, and the Rules and Regulations of this Commission.

2. THE COMMISSION FURTHER FINDS that notice is proper in this Cause and complies with Order No. 667373 and the requirements of OAC 165:5-7-51.

OIEC Motion

3. THE COMMISSION FURTHER FINDS that, regarding the OIEC Motion, the Commission does not rely upon testimony that inappropriately relies upon previous settlement agreements as precedential.

4. THE COMMISSION FURTHER FINDS that parties shall not rely upon, and shall not file or elicit testimony that relies upon, provisions of settlement agreements that explicitly provide that they are not binding in other proceedings and are not to be cited as precedent, or that contain similar language, except where necessary to enforce the terms of the settlement agreement or to determine rights arising under the settlement agreement.

Test Year

5. THE COMMISSION FURTHER FINDS that a review of a utility company's rates relies on an investigation of the test year, a "mirror view of the past suspended within a limited but definite time frame through which we prophesy its duplication in the future." *Sw. Pub. Serv. Co. v. State*, 1981 OK 136, ¶ 14, 637 P.2d 92, 98. PSO is entitled to the opportunity to earn a fair rate of return on its property invested and in use during the test year, *see id.*; *Lone Star Gas Co., a div. of Enserch Corp v. State*, 1986 OK 53, ¶ 4, 745 P.2d 723, 725, after making known and measurable adjustments for changes occurring within six months after the test year, 17 O.S. § 284. PSO is also entitled to include reasonable operating expenses necessary to provide service with its investments. *Turpen v. Okla. Corp. Comm'n*, 1988 OK 126, ¶ 10 n.7, 769 P.2d 1309, 1316 n.7.

6. THE COMMISSION FURTHER FINDS that the test year in this Cause is the twelve-month period ended December 31, 2016. The Commission's Minimum Standard Filing Requirements, specifically OAC 165:70-1-2, define "test year" as the "twelve (12) month period used in determining rate base, operating income and rate of return." Title 17, § 284 of the Oklahoma Statutes provides for consideration of changes beyond the test year as follows:

> In its review and examination of an application by a utility to change its rates and charges pursuant to Sections 137, 152 or 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.

7. THE COMMISSION FURTHER FINDS that Commission Order No.657877 as modified by Order No. 658529 in Cause No. PUD 201500208 set rates as determined by the last PSO rate case. Testimony was offered by multiple witnesses that stated the new rates approved in Cause No. PUD 201500208 were effective beginning January 2017, outside of the test year for this Cause.

8. THE COMMISSION FURTHER FINDS that the test year in this Cause is the twelve-month period ended December 31, 2016, and that pursuant to 17 O.S. § 284, the six-month post test year period ended on June 30, 2017.

Legal Standard

9. THE COMMISSION FURTHER FINDS that PSO bears the burden of proof with regard to whether its investments are in service and as to the reasonable level of expenses necessary to provide service. Indeed, the "burden of proof with respect to every element of value entering into the rate base is upon the public utility." *Mullendore Gas Co. v. City of Stillwater*, 1926 OK 325, ¶ N, 250 P. 895, 898-99 (citing *Okla. Nat. Gas. Co. v. Corp. Comm'n of Okla.*, 1923 OK 400, 216 P. 917.) The "burden of proof rests on [the utility company], not the Corporation Commission." *Lone Star Gas Co., a Div. of Enserch Corp. v. Corp. Comm'n of State of Okla.*, 1982 OK 79, ¶ 4, 648 P.2d 36, 42.

Plant in Service

10. THE COMMISSION FURTHER FINDS that PSO's plant balances are clearly known and measurable at the end of the six-month post-test year period. All projects actually completed and in service within six-months of test year-end should be included in rate base. The Commission finds that the utility plant in service balance as of June 30, 2017, should be adopted as the utility plant in service balance to be included in the rate base in this Cause.

11. THE COMMISSION FURTHER FINDS that the gross amount of plant in service at the June 30, 2017, six-month post-test year-end of $5,052,446,776 is set forth in the filed Issues Spreadsheet ($4,983,250,551 + $69,196,225). This includes both Plant in Service recorded in FERC Account 101 and Completed Construction Not Classified recorded in FERC Account 106. No party opposed the prudence of any of the capital additions made since the last rate case through the six-month post-test year period of June 30, 2017.

12. THE COMMISSION FURTHER FINDS that Construction Work in Progress ("CWIP") not in service as of June 30, 2017, is not included in rate base. Since the Commission has adopted the Plant in Service balance as of June 30, 2017, the Commission finds that no CWIP should be included in the rate base of PSO. No adjustment is necessary to reflect this decision, since the booked plant in service as of June 30, 2017, captures all CWIP requested for those plants that were actually placed in service as of June 30, 2017.

Accumulated Depreciation

13. THE COMMISSION FURTHER FINDS that all parties recommended an increase to Accumulated Depreciation to update for the six-month post-test year level. Mr. Farrar and Mr. Garrett recommend the balance provided by the Company while Ms. Weber recommends a lower amount and includes an adjustment to move the Northeastern Unit 4 balance to a regulatory asset. (Weber Rev. Req. Resp. Test. at 45:7-48: table, Farrar Rev. Req. Resp. Test. at 6:19, M. Garrett Rev. Req. Resp. Test. at 8: Table 1:2, Hamlett Reb. Test. at 23:10 -15.) The recommendations of Mr. Garrett and Mr. Farrar matched the data request responses provided to the parties by PSO. Mr. Hamlett agreed with Mr. Farrar's and Mr. Garrett's adjustment of $32,673,645. (Hamlett Rebuttal, p. 23, lines 8-13.)

14. THE COMMISSION FURTHER FINDS that the balance of accumulated depreciation be increased by $32,673,645 in order to give effect to the known and measurable increase in the deferred taxes that occurred within six months of the test year end.

Prepaid Pension

15. THE COMMISSION FURTHER FINDS that PSO included $92,361,841 in prepaid pension assets, the 13-month average balance at December 31, 2016, in rate base. Applying PSO's overall grossed-up[1] return results in an annual revenue requirement of approximately $6.4 million. When compared to the pension cost savings of $11.9 million

[1] The grossed-up return includes an amount for the taxes that the Company will have to pay on the amount such that, after-tax, the Company will earn its requested weighted average cost of capital.

generated by the additional pension contributions, the benefit to PSO's customers is approximately $4.7 million. (Hamlett Direct, p. 31, lines 13-20.) The prepaid pension asset produces benefits for PSO's customers.

16. THE COMMISSION FURTHER FINDS that the prepaid pension assets are decreased by $344,729 to account for the six-month post-test year values. (Patel Direct, p. 5, line 9.)

17. THE COMMISSION FURTHER FINDS that OIEC and the Attorney General recommended the removal of the 2003 beginning balance associated with the pension prepayment. (Farrar Responsive, p. 8, lines 2-3 and Garrett Responsive, p. 9, lines 14-16.)

18. THE COMMISSION FURTHER FINDS that the 2003 pension prepayment balance was approved by the Commission and included in rate base in previous rate cases including Cause No. PUD 201500208 and this balance will continue to be allowed in rate base consistent with previous Commission treatment. (Hamlett Rebuttal, p. 18, lines 5-10.)

Materials and Supplies and Fuel Inventory

19. THE COMMISSION FURTHER FINDS that PSO has included in its rate base the 13-month average balance of materials and supplies and fuel inventories through December 31, 2016, in the amount of $62,391,612 (Schedule B-2) as required by OAC 165:70-5-22(4). The Attorney General and OIEC adjusted the materials and supplies inventory by a reduction of $5,886,208. PSO did not contest this adjustment. (Hamlett Rebuttal, p. 26, lines 1–3 and Issues Spreadsheet.)

20. THE COMMISSION FURTHER FINDS that materials and supplies inventory shall be reduced by $5,886,208.

21. THE COMMISSION FURTHER FINDS that PSO made an adjustment to PSO's fuel inventory in working capital by decreasing a 13-month average Coal Inventory provided on WPB-05, p. 1 of 3, by $10,061,281 for the test year-end value by $11,016,346 to incorporate the optimal target level of tons required at PSO's coal-fired plants (Northeastern Unit 3 and Oklaunion) necessary to provide reliable service to its customers. (Hamlett Direct, p. 37, lines 3-7.) Ms. Patel and Mr. Farrar recommend an increase of $289,914. PSO did not contest the adjustment. (Hamlett Rebuttal, p. 26, lines 4-7.) The Commission adopts the adjustment proposed by PUD witness Patel and Attorney General witness Farrar.

Off-system Trading Deposits

22. THE COMMISSION FURTHER FINDS that PSO reduced rate base by $63,582 for Off-System Trading Deposits which represents the net amount of funds deposited by and with PSO for its off-system purchase and sales activities on its books at the test year-end. During the test year, PSO had less funds on deposit with counter parties than it required from counter parties resulting in the test year rate base reduction. These funds are required both by PSO and of PSO as security for purchase and sales activities.

23. THE COMMISSION FURTHER FINDS that an adjustment be made to increase the thirteen-month average balance of off-system trading deposits by $84,403 to reflect the balance as of June 30, 2017. (Patel Rev. Req. Resp. Test. at 10:5-9.)

Independent Power Producer ("IPP") System Upgrades

24. THE COMMISSION FURTHER FINDS that rate base shall be reduced by the IPP transmission credits of $1,050,066, which represent funds deposited with PSO by IPPs to off-set the transmission system upgrades necessary to interconnect the IPPs with PSO's transmission system. Since these funds were supplied by the IPPs, as required by FERC Order 2003, and not supplied by PSO investors, they are a reduction to PSO's rate base. However, PSO proposed this amount in its Application; therefore, no adjustment is required.

Accumulated Deferred Income Taxes

25. THE COMMISSION FURTHER FINDS that accumulated deferred income taxes should be updated to recognize the six-month post-test year balance. (Walkup Resp. Test. 16:18-19; Garrett Rev. Req. Resp. Test. at 8: Table 1:3; Farrar Rev. Req. Resp. Test. at 11:20-12:8.) This adjustment gives effect to the known and measurable increase in the deferred taxes that occurred within six months of test year-end. When additions to the investment levels in Plant are recognized through the 6-month period, off-setting increases in Accumulated Depreciation and Accumulated Deferred Income Tax must also be recognized. This adjustment will increase Accumulated Deferred Income Tax, resulting in a decrease to rate base of ($39,357,904). (Walkup Responsive Testimony, filed September 21, 2017, pages 16-17.)

26. THE COMMISSION FURTHER FINDS that the following reductions to rate base be adopted: $4,937,384 for excess deferred income taxes (Schedule B-2) as required by OAC 165:70-5-22(4), $15,971 for deferred investment credits (pre-1971) (Schedule B-2) as required by OAC 165:70-5-22(4) and $31,211,048 of deferred state investment tax credits (Schedule B-3, Line 29) as required by OAC 165:70-5-22(4). (It is noted that no party objected to these reductions recommended by PSO.)

Red Rock Regulatory Asset

27. THE COMMISSION FURTHER FINDS that in Commission Order No. 554328, issued in Cause No. PUD 200700465, PSO was permitted to defer as a regulatory asset a total of $10,508,157 for costs associated with the Red Rock Generation Station. The Commission further ordered that as of March 1, 2008, PSO could begin accruing a carrying cost equal to PSO's Allowance for Funds Used During Construction ("AFUDC") rate until the regulatory asset is recovered in base rates. (Order No. 554328, issued May 21, 2008, in Cause No. PUD 200700465, pp. 3-4,)

28. THE COMMISSION FURTHER FINDS that the Red Rock regulatory asset, with the balance reflected as of June 30, 2017, be included in rate base, consistent with Commission Order No. 554358.

Medicare Part D Regulatory Asset

29. THE COMMISSION FURTHER FINDS that the Medicare Part D subsidy regulatory asset of $3,919,320 (Hamlett Direct, page 33), will continue as approved in Cause No. PUD 201300217. The Commission previously approved deferral of these costs as a regulatory asset along with ongoing amortization. (Hamlett Direct, p. 34, line 19 through p. 35, line 17.)

Contributions in Aid of Construction

30. THE COMMISSION FURTHER FINDS that PSO reduced rate base for $378,434 of refundable Contribution in Aid of Construction. (Hamlett page 33 and page 36, lines 19–23.) Mr. Farrar recommended that regulatory liabilities, including Contributions in Aid of Construction, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Test. 7:6.) PUD also recommended this update and PSO agreed with PUD.

31. THE COMMISSION FURTHER FINDS and adopts PUD's recommendation to increase the Refundable Contribution in Aid of Construction adjustment in the amount of $69,740 which reduces the rate base by $69,740.

Deferred Storm Expense

32. THE COMMISSION FURTHER FINDS that the balance of previously deferred storm costs being recovered from customers would be $3,854,154 as of June 30, 2017. (Hamlett Direct, page 33 and page 34, lines 15–18.) Mr. Hamlett also testified there were six storms for which each storm's restoration efforts exceeded $1 million. The total of these six storms was $29,000,397. (Hamlett Direct, page 36, lines 8 through 11.) No party objected to the inclusion of the past storm regulatory asset deferrals in rate base. PSO has included the appropriate amount of storm regulatory asset deferrals in rate base.

33. THE COMMISSION FURTHER FINDS that amortization of storm costs will occur over four years consistent with Order No. 639314 issued in Cause No. PUD 201300217 (Hamlett Direct page 6, line 20 through page 7, line 8.)

34. THE COMMISSION FURTHER FINDS that the Attorney General recommended that regulatory assets, including the deferred storm expense, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Resp. Test. at 7:5.) The deferred storm expense regulatory asset requested by PSO is increased by $4,625,004 to the June 30, 2017, balance of $8,479,158.

Deferred Environmental Asset

35. THE COMMISSION FURTHER FINDS that Order No. 657877, issued in Cause No. PUD 201500208, addressed certain plant investment attributable to PSO's environmental compliance plan not in service as of July 31, 2015.

36. THE COMMISSION FURTHER FINDS that the time period for the environmental compliance plan deferral recoveries would be the date new rates are implemented in 2018 through 2040.

37. THE COMMISSION FURTHER FINDS that PUD witness Ms. Weber directly addressed the environmental deferral regulatory asset while Attorney General witness Mr. Farrar and OIEC witness Mr. Mark Garrett indirectly addressed it through their six-month post-test year updates. All of those witnesses either directly or indirectly recommended the value of the environmental deferral regulatory asset be set at the six-month post-test year level (June 30, 2017) amount.

38. THE COMMISSION FURTHER FINDS that adjustments recommended by PUD are adopted as set forth below:

a. The Commission find and adopt PUD's recommendation to increase rate base in the amount of $13,082,073 to record the balance in the Deferred Environmental Accounting Regulatory Asset account as of 12/31/16 which was omitted from PSO's pro forma adjustment listed on Schedule B.

b. The Commission find and adopt PUD's recommendation to remove PSO's pro forma adjustment for amortization of the Deferred Environmental Accounting Regulatory Asset for January 1, 2018, through June 30, 2018, which is a rate base increase of $968,689.

c. The Commission find and adopt PUD's recommendation to correct PSO's pro forma Deferred Environmental Accounting Regulatory Asset balance for corrections to calculations of depreciation, ad valorem taxes, tax depreciation and associated accumulated deferred income taxes, cost of capital grossed-up for income taxes, and omitted Comanche Generation Plant investments. The recommendation increases rate base by $531,524.

d. The Commission find and adopt PUD's recommendation to remove the monthly carrying charges on the Deferred Environmental Accounting Regulatory Asset for periods prior to June 30, 2017, which were before the regulatory asset is properly included in rate base. The PUD recommendation reduces rate base by $1,139,884.

e. The Commission find and adopt PUD's recommendation to reduce the Deferred Environmental Accounting Regulatory Asset included in PSO's pro forma rate base by $12,738,287 for the amounts included from July 1, 2017, through December 31, 2017, which are not known and measurable as the investments for those periods on which the balances were calculated were estimated to have no changes after 6/30/17.

f. The Commission find and adopt PUD's recommendation to decrease the revenue requirement by $1,380,888, the amount by which PSO's pro forma depreciation exceeded the depreciation of the Oklaunion AROs for the Ash Ponds after correcting the service life from 2020 to the estimated retirement date of the Oklaunion Plant of 12/31/2046.

Deferred Pole Attachment Revenue

39. THE COMMISSION FURTHER FINDS that rate base is reduced by $799,015 for deferred pole attachment revenue. (Hamlett page 33 and page 37, lines 1 – 4). No party objected to this rate base reduction.

40. THE COMMISSION FURTHER FINDS that the Attorney General recommends that regulatory liabilities, including the deferred pole attachment revenue, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Resp. Test. at 7:6.) The deferred pole attachment revenue regulatory liability requested by PSO is reduced by $788,115 to the June 30, 2017, balance of $0.

Non-AMI Meters

41. THE COMMISSION FURTHER FINDS that PSO is in compliance with Order No. 639314 as to the non-AMI meters. No party objected to including the appropriate amount of non-AMI meter regulatory asset in rate base consistent with Commission Order No. 639314 issued in Cause No. PUD 201300217. The Commission approves the inclusion of the non-AMI regulatory asset in PSO's rate base.

42. THE COMMISSION FURTHER FINDS that regulatory assets, including the non-AMI meters, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Resp. Test. at 7:5.) The non-AMI meter regulatory asset requested by PSO is reduced by $7,773,107 to the June 30, 2017, net balance of $42,358,000.

43. THE COMMISSION FURTHER FINDS that the non-AMI regulatory asset amortization will change on the date new base rates are implemented in this case and will continue through December 31, 2027.

44. THE COMMISSION FURTHER FINDS and adopts PUD's recommendation to decrease the revenue requirement by $2,219,213 due to correction of Non-AMI Meters Regulatory Asset amortization rate to be based on the net book value of the Non-AMI Meters and amortized through December 31, 2027.

ARO Retired Plant

45. THE COMMISSION FURTHER FINDS that Asset Retirement Obligations ("ARO") recorded pursuant to financial accounting standards. PSO's treatment of ARO obligations in this case is consistent with the treatment in Cause Nos. PUD 200600285, PUD 200800144, PUD 201000050, PUD 201300217 and PUD 201500208. (Hamlett Direct, p. 22, lines 20-23, and p. 23, lines 1-2, and lines 10-20.)

46. THE COMMISSION FURTHER FINDS and accepts the ARO retired plant balance requested by PSO of $539,767.

Deferred Severe Storm Expense

47. THE COMMISSION FURTHER FINDS that regulatory assets, including the deferred severe storm expense, be updated to the balances at June 30, 2017. (Farrar Rev. Req. Resp. Test. at 7:5.) The deferred severe storm expense regulatory asset requested by PSO is increased by $6,363,372 to the June 30, 2017, balance of $35,363,769.

Customer Deposits

48. THE COMMISSION FURTHER FINDS that a customer deposit represents funds provided by the customer rather than investors. Thus, these funds are used to reduce PSO's rate base. This Commission has consistently treated customer deposits as a reduction to rate base. (Hamlett Direct, p. 33, lines 1-15.)

49. THE COMMISSION FURTHER FINDS that PSO reduced rate base for the $49,674,708 of customer deposits recorded on its books at December 31, 2016, the test year-end.

50. THE COMMISSION FURTHER FINDS that PUD, the Attorney General and OIEC recommended an increase of $986,714 based on the balance of customer deposits at June 30, 2017. According to Mr. Hamlett, adjusting the balance at June 30, 2017, was consistent with PSO's original filing and will result in an additional reduction of $986,714 to PSO's requested rate base. Mr. Hamlett agreed with the adjustment. (Hamlett Rebuttal, p. 26, lines 14-17.) The Commission adopts this adjustment of customer deposits as being appropriate and consistent with how this Commission has treated customer deposits as a reduction to rate base in the past.

Northeastern Unit 4

51. THE COMMISSION FURTHER FINDS that, in PSO's previous rate case, Cause No. PUD 201500208, the Commission deferred consideration on the regulatory treatment of Northeastern Unit 4 because the unit was still in service. "The determination of stranded cost recovery relating to PSO's Northeastern No. 4 Unit should be addressed in PSO's next rate case, following PSO's retirement of Northeastern No. 4 Unit, after Northeastern No. 4 Unit is no longer providing service to the public and is no longer used and useful." (Final Order, Order No. 657877, Cause No. PUD 201500208, p. 10.).

52. THE COMMISSION FURTHER FINDS that PSO retired Northeastern Unit 4, as scheduled, in April 2016, and has no plans to return the unit to service. (Fate Direct Test. at 14:20-21.) Furthermore, PSO is not taking steps necessary to maintain Northeastern Unit 4 to bring the unit back into service at a later date. With each day, the probability of a future return to service diminishes further. However, the Company does not plan to demolish Northeastern Unit 4 as long as Northeastern Unit 3 remains in service (10/30/17 A.M. Tr. at 52:4-20).

53. THE COMMISSION FURTHER FINDS that PSO asserts that the various components of its environmental compliance plan are linked. Each component is part of the overall environmental compliance plan. PSO argued that because the Commission allowed reasonably-incurred costs for the environmental compliance plan to be recovered through base rates by Order No. 657877, then all reasonably-incurred costs to achieve overall compliance should be recovered. Therefore, the Company is requesting the continued recovery of the undepreciated book value of Northeastern Unit 4 as well as a return on the net book value of the asset at the weighted average cost of capital (Fate Direct Test. at 14:8-17). However, as has already been addressed above, the Commission did not in the previous rate case include Northeastern Unit 4 in the environmental compliance plan. In fact, the Commission addressed

Northeastern Unit 4 separately and directed determination of stranded costs be addressed in this Cause, PSO's next rate case.

54. THE COMMISSION FURTHER FINDS that Northeastern Unit 4 provided nearly 36 years of service to PSO customers.

55. THE COMMISSION FURTHER FINDS that initially Northeastern Unit 4 had an established service life of thirty one (31) years. The initial estimate of the life of Northeastern Unit 4 was fairly close to actual life span. In 2006, the Commission established a sixty (60) year service life (10/30/17 A.M. Tr. At 34:14-35:24). Due to environmental, technological and/or physical obsolescence the service life and depreciation rates set in the past were insufficient to allow for a full recovery of the cost of Northeastern Unit 4.

56. THE COMMISSION FURTHER FINDS that it is fair, just and reasonable for PSO to obtain **recovery of** Northeastern Unit 4. using depreciation methods consistent with those recommended in this Cause.

57. THE COMMISSION FURTHER FINDS that the concept of "used and useful" is a fundamental longstanding ratemaking concept in which a utility's opportunity to earn a return is limited to only those assets that are used (i.e., not under construction or standing idle awaiting abandonment) and useful (i.e., actively helping the utility provide efficient service).

58. THE COMMISSION FURTHER FINDS that in Oklahoma, ratepayers are only required to pay rates based upon the value of a public utility's investments that are used and useful in providing service to the public at the time the rates are set. *Turpen v. Oklahoma Corporation Commission,* 1988 OK 126, 769 P.2d 1309, 116 n. 7; *Southwestern Public Service Co. v. State,* 1981 OK 136, 637 P.2d 92, 97. As further explained in Southwestern Public Service Co.:

> In the case of *Oklahoma Natural Gas Co. v. Corporation Commission*, this court said: "In determining whether the rate is reasonable, it is necessary to ascertain the fair value of the property of the appellant used and useful in its public service business at the time the inquiry was made . . . for appellant is entitled to a rate which will yield a fair return upon the reasonable value of the property *at the time it is being used for the public*;" [emphasis added].

Southwestern, ¶ 13, 637 P.2d at 97.

59. THE COMMISSION FURTHER FINDS that Northeastern Unit 4 is not used or useful to PSO customers and PSO should not obtain a return on or **recovery on** Northeastern Unit 4 since Northeastern Unit 4 is not being used to supply power to the public at this time.

Cash Working Capital ("CWC")

60. THE COMMISSION FURTHER FINDS that PSO reduced its rate base by $110,725,044 to reflect the CWC allowance determined by a lead-lag study. (Hamlett Direct, p. 24, lines 14-21.)

61. THE COMMISSION FURTHER FINDS and adopts PUD's recommended methodology to adjust for CWC . After adjustment posed by the ALJ in this report, CWC increases rate base by $3,420,650. (Walkup Responsive, p. 6, lines 1-4 and ALJ Accounting Exhibit attached hereto as Attachment A).

Cost of Capital: Capital Structure, Cost of Debt, Return on Equity & Rate of Return

62. THE COMMISSION FURTHER FINDS the cost of capital for a public utility represents the return on investment the Company has the opportunity to earn from providing service. The cost of capital is typically calculated as the weighted average of debt and equity with weights relying on the capital structure, or percentage of capital from debt and from equity investors (Rush Rev. Req. Resp. Test. at 37:16-38:7).

63. THE COMMISSION FURTHER FINDS that multiple witnesses agreed with the Company's proposed capital structure of 51.5 percent debt and 48.5 percent equity and the proposed cost of debt of 4.60 percent. (Vilbert Rebuttal, p. 2, lines 7-9; Parcell Responsive , p. 2, lines 20-24; Reno Responsive, p. 4, lines 5-6; Griffing Responsive, p. 38, lines 11, 17; Rush Responsive, p. 6, lines 18-20.) No party objected to PSO's proposed capital structure. The Commission adopts PSO's proposed capital structure of 51.5 percent debt and 48.5 percent equity.

64. THE COMMISSION FURTHER FINDS that PSO's Application proposes the adjusted test year long-term debt costs of 4.60 percent. No party contests this cost of debt. The Commission finds that PSO's embedded cost of long-term debt is 4.60 percent.

65. THE COMMISSION FURTHER FINDS that the return on equity represents one of the most difficult values in a rate case proceeding because it must be estimated using expert witnesses' models and judgment. (Griffing Resp. Test. at 10:6-13; Parcell Rev. Req. Resp. Test. at 20:6-10.) The resulting return on equity must offer the public utility the opportunity to earn a fair return on its investment, allowing a return similar to returns on other similarly risky investments, providing confidence in the financial integrity of the company, and allowing the company to attract capital. *See Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

66. THE COMMISSION FURTHER FINDS that in this Cause, most expert witnesses presented the results of various Discounted Cash Flow ("DCF") models and models derived from the Capital Asset Pricing Model ("CAPM"). (Griffing Resp. Test. at 10:9-11, 28:3-34:19; Vilbert Dir. Test. at 38:21-23, 47:9-21; Parcell Rev. Req. Resp. Test. at 20:9-10.) Some witnesses compared those results to the rates of return awarded in other regulatory jurisdictions over a recent period of time. (Griffing Resp. Test. 35:4-36:7; Parcell Rev. Req. Resp. Test. at 28:29-31.)

67. THE COMMISSION FURTHER FINDS that to estimate the return on equity using either a DCF model or models derived from CAPM, the experts first developed a set of comparison companies with risks and operations similar to PSO. (Griffing Resp. Test. at 12:8-18; Vilbert Dir. Test. at 30:8-15; Parcell Rev. Req. Resp. Test. at 20:14-21:6; Rush Rev. Req. Resp. Test. at 17:4-13.) For the DCF, the experts calculated the dividend yield for each

comparison company, then adjusted the yield to include a growth rate. (Griffing Resp. Test. at 10:15-11:7; Vilbert Dir. Test. at 36:5-13; Parcell Rev. Req. Resp. Test. at at 21:28-22:3.) The experts differed on the growth rates used, although many favored the use of analysts' estimates of forward-looking growth rates. (Griffing Resp. Test. at 22:2-23:8; Vilbert Dir. Test. at 37:25-38:4; Parcell Rev. Req. Resp. Test. at 23:4-13; Rush Rev. Req. Resp. Test. at 23:9-10.) The experts could then average the results of these return values across all comparison companies to generate a return on equity result.

68. THE COMMISSION FURTHER FINDS that even though the experts differed on the comparison companies used and in the manner some calculations were performed, many of the experts' results from the DCF model calculated in the above manner fall in a similar range from 8.54 to 8.83 percent. (Griffing Resp. Test. at 27:14-15; Vilbert Dir. Test. at App. C, 36, Schedule No. MJV-6; 11/1/17 Early P.M. Tr. at 28:20-29:14, 92:3-93:17; Rush Rev. Req. Resp. Test. at 16-18.) The biggest difference between the final recommendations arises in part from Dr. Vilbert, the expert for PSO, using what he calls the financial risk adjustment. (11/2/17 Late P.M. Tr. at 20:7-11.)

69. THE COMMISSION FURTHER FINDS that the other ROE expert witnesses in this Cause disagreed with Dr. Vilbert's financial risk or leverage adjustment. (Griffing Resp. Test. at 42:16-43:21; Parcell Rev. Req. Resp. Test. at 34:20-35:7.) Mr. Parcell, for example, explained that equating comparison companies' market-based capital structures with PSO's book-value capital structure would result in a significantly higher return on equity. (Parcell Rev. Req. Resp. Test. at 35:4-14.) Further, it was established on cross-examination that Dr. Vilbert's adjustment was "not typically used in regulatory proceedings like this one" and that he could not provide any examples of the adjustment being used in Oklahoma or even by a public service commission in the continental United States. (11/1/17 Early P.M. Tr. at 30:13-14, 54:5-58:6, 63:14-17.) He agreed that before the adjustment, his simple DCF model produced an estimated return on equity of 8.8 percent. (11/1/17 Early P.M. Tr. at 93:10-13.)

70. THE COMMISSION FURTHER FINDS that the ROE expert witnesses disagreed on the significance of recently awarded returns on equity from other jurisdictions. Dr. Vilbert represented that these results were around 9.5 percent, meaning that the Commission should award a return higher than 9.5 percent. (Vilbert Reb. Test. 10:7-21.) The other experts argued that recently awarded returns on equity were in a range from around 9.0 percent to around 10.0 percent, meaning that returns around 9 percent were reasonably close to recently awarded returns. (Griffing Resp. Test. at 37:3-12; Parcell Rev. Req. Resp. Test. at 31:10-20.)

71. THE COMMISSION FURTHER FINDS that the financial risk or leverage adjustment recommended by PSO's witness, Dr. Vilbert, is rejected. The adjustment is not currently accepted in regulatory proceedings in the United States and tends to over-state the required return on equity.

72. THE COMMISSION FURTHER FINDS that the return on equity recommendations by a majority of ROE experts are largely concentrated around 8.83 percent to 9.0 percent. For example, Dr. Griffing recommended a reasonable range of exactly that amount, while Mr. Parcell recommended a 9.0 percent return on equity and Mr. Rush recommended 8.9 percent. The Commission therefore adopts a 9.0 percent as the return on equity in this cause.

73. THE COMMISSION FURTHER FINDS that the overall rate of return that results from the capital structure and cost of capital determined above is 6.73 percent. (Exhibit 65, p. 33.)

Description	Capital Ratio	Cost Rate	Weighted Average Cost
Long Term Debt	51.49%	4.60%	2.37%
Common Equity	48.51%	9.00%	4.37%
Total Capital	100%		6.73%

Payroll

74. THE COMMISSION FURTHER FINDS that PSO proposes an increase to test year levels of payroll in the amount of $2,726,115.00 for PSO and $2,773,667.00 for American Electric Power Service Company ("AEPSC") payroll. (Exhibit 66 p. 55.) To determine the appropriate payroll level for PSO, the Company used the base payroll amounts for each employee at test year end, a known and measurable amount. That amount was then increased by 3.5 percent to reflect the known and measurable pay increase for 2017 that has been implemented. (Hamlett Rebuttal, p. 18, lines 9-15, and Exhibit 138, p. 29) PSO's adjustment recognized the normal turnover of employees during the test year because it used the test year-end employees and their actual salary at year-end before applying the known and measurable 2017 pay increase. (Hamlett Rebuttal, p. 30, lines 6-9.)

75. THE COMMISSION FURTHER FINDS that PSO competes in a national labor market against regulated and unregulated companies, as well as AEP's own internal system for highly trained, specialized and mobile personnel. PSO has found it more effective to pay a consistent, nationally competitive rate across its system, which is typical practice for other companies of AEP's size and geographic diversity. (Tr. 11/1 AM at pp. sd-99, lines 1-24; sd-100, line 24 to sd-101, line 8.)

76. THE COMMISSION FURTHER FINDS that PUD reviewed PSO's proposed adjustment to increase O&M expenses to reflect base payroll in the amount of $2,727,075. According to Mr. Rush the adjustment included the raises implemented in April 2016 and in the fall of 2016, and raises implemented in April 2017, and for the fall of 2017. (Rush Responsive, p. 41, lines 13-18.) According to Mr. Rush, PSO's workpapers complied with the Commission's rules and annualized the level of salaries and wages, and PUD did not have any adjustments to make after its review of payroll expense. (Rush Responsive, p. 42, lines 10-12.)

77. THE COMMISSION FURTHER FINDS that PSO provided WP H-4-6, Wage and Salary Surveys, as required by OAC 165:70-5-22(4). No party opposed these Wage and Salary Surveys which guide PSO's compensation levels. PUD, after review of this information, made no adjustment, finding that:

> The Company needs employees with a particular set of experience, knowledge, and skills to provide efficient and affordable electric service to its customers. As such, PUD believes that it is prudent for the Company to have a robust payroll

plan as an important part of employee attraction and retention. In addition, after reviewing the surveys provided by Willis Towers Watson, PUD believes that the compensation practices of the Company are aligned with the compensation practices of its peer group.

Rush Responsive at p. 42, lines 2-8.

78. THE COMMISSION FURTHER FINDS and approves PSO's requested payroll expenses as guided by the Wage and Salary Surveys, including the amounts billed to PSO by AEPSC, because it is a known and measurable change that recognizes actual employees and their salaries at the end of December 2016 and approved raises in 2017 that have been implemented.

Supplemental Executive Retirement Plan ("SERP")

79. THE COMMISSION FURTHER FINDS that it has consistently disallowed recovery of SERP costs in previous rate cases involving PSO. (Cause No. PUD 200600285, Cause No. PUD 200800144, and Cause No. PUD 201500208.) SERP expenses are consistently disallowed in other jurisdictions. (Exhibit 66, p. 45.) As stated in Order No. 658529 in Cause No. PUD 201500208, the Commission finds that for rate-making purposes, utility shareholders should bear the additional costs associated with supplemental benefits to executives.

80. THE COMMISSION FURTHER FINDS and disallows SERP costs in this Cause based on the premise that ratepayers should pay for all of the executive benefits included in the Company's regular pension plans while shareholders should pay for the additional benefits included in the supplemental plan. Mr. Farrar and Mr. Garrett both recommended that PSO's requested non-qualified pension expense be borne by the shareholders. (Farrar Rev. Req. Resp. Test. at 23:12-18; Rev. Req. Resp. Test. at 46:3-6.) The employees that receive this benefit are highly compensated to align their interests with shareholders. (Garrett Rev. Req. Resp. Test. at 46:6-14) Therefore, the Commission finds that SERP expense in the amount of $96,780.00 for PSO and $253,082.00 for AEPSC are excluded from PSO's rates.

Incentive Compensation—short term and long term

81. THE COMMISSION FURTHER FINDS that witnesses, Mr. Farrar and Mr. Garrett both recommended adjustments to the Company's incentive compensation plans. (Farrar Rev. Req. Resp. Test. at 21:17-19; Garrett Rev. Req. Resp. Test. at 32:15-17.) Mr. Farrar recommended that 50 percent of the annual incentive plan be excluded from rates and Mr. Garrett recommended that 75 percent of those costs be excluded. Mr. Farrar testified that 75 percent of the test year level of the incentive plans funding was based on the Company's operating earnings per share in 2016, and that this was reduced to 70 percent for 2017. (11/6/17 Early P.M. Tr. at 92:9-12.) Mr. Farrar testified that according to the Company's 2017 Proxy Statement, the award level for that financial component was 195.5 percent of the target level in 2016. (11/6/17 Early P.M. Tr. at 92:15-19.) Mr. Carlin of PSO testified that the operating earnings per share threshold for 2017 was $3.55 per share. (11/1/17 A.M. Tr. at 79:16-17.) This is a reduction from the $3.65 operating earnings per share threshold for the previous year, 2016. (11/6/17 Early P.M. Tr. at 16:9-13.) Mr. Farrar testified that the actual impact of this financial component on bonuses could be 140 percent of the target level, and that would certainly be

understood by PSO's employees. (11/6/17 Early P.M. Tr. at 93:3-6). Even though the financial aspect of the annual incentive plan clearly produced most of the incentive plan's cost, Mr. Farrar limited his adjustment to 50 percent of the target level because it had been the Commission's practice to share the costs evenly between shareholders and ratepayers. (Farrar Rev. Req. Resp. Test. at 21:17-19.)

82. THE COMMISSION FURTHER FINDS that the annual incentive plan expenses be reduced by $4,863,954 to exclude 50 percent of the target level of this expense from the revenue requirement.

83. THE COMMISSION FURTHER FINDS that Mr. Farrar and Mr. Garrett both recommended adjustments to exclude 100 percent of the long-term incentive plan costs from rate recovery. (Farrar Rev. Req. Resp. Test. at 22:12-13; Garrett Rev. Req. Resp. Test. at 40:13-18.) The long-term incentives are provided to highly compensated employees to align their interests and loyalty to shareholders. (Garrett Rev. Req. Resp. Test. at 40:15-41:3.) These costs are not essential to serve the ratepayer and should be excluded from rate recovery. The performance measures used in the long-term incentive program are based on achieving financial goals that benefit shareholders and thus should not be borne by ratepayers. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interests of shareholders first.

84. THE COMMISSION FURTHER FINDS that the adjustment recommended by the Attorney General and by OIEC to reduce expenses by $3,106,766 is adopted.

<u>Capitalized Incentives</u>

85. THE COMMISSION FURTHER FINDS that there is no finding in the Cause that PSO's incentive compensation costs are unreasonable and therefore declines to adopt the adjustment proposed by OIEC witness Mark Garrett to reduce rate base by $37,645,259 for capitalized incentives. (Garrett Responsive, p. 12.)

<u>Dues and Donations and credit line fee expense</u>

86. THE COMMISSION FURTHER FINDS that the following PUD adjustments be adopted:

a. PUD's recommendation that the Commission accept PSO's proposed adjustment No. WP H-2-27 to decrease PSO's cost of service by $173,678 to exclude expenses that are not allowed for ratemaking purposes. (Aguirre Responsive Testimony, filed September 21, 2017, pages 6-8.)

b. PUD's adjustment to No. H-2 to decrease Dues and Donations by $117,876. (Aguirre Responsive Testimony, filed September 21, 2017, pages 8-9.)

c. PUD's recommendation that the Commission accept PSO's proposed $678,104 adjustment No. WP H-2-9 to reclassify Credit Line Fee Expense to

Administrative and General Expense. (Aguirre Responsive Testimony, filed September 21, 2017, pages 9-13.)

Factoring

87. THE COMMISSION FURTHER FINDS THAT Factoring Expense is expense associated with the collection of billed revenue and is determined based upon the Company's revenue. The Commission accepts PUD's recommendation to decrease the Factoring Expense in the amount of ($1,244,786).

New Storm Costs

88. THE COMMISSION FURTHER FINDS that PSO proposes to increase storm damage expense by $8,264,000.00, from $2,936,000.00 to $11,200,000.00 (Hamlett Direct p.8 Lines 1-10), which is the seven-year average experienced by the Company for storm expense from 2010 through 2016.

89. THE COMMISSION FURTHER FINDS that the Attorney General opposed this for three reasons: (1) PSO has made significant investments to its distribution system, (2) a lower base rate allowance with a later recovery of additional expenses ensures PSO has appropriate incentives to minimize storm damage recovery expenses, and (3) it is an inappropriate time to request recover for uncollected storm damage expenses and to increase the base rate allowance. (Alexander Rev. Req. Resp. Test. at 5:9-18.) The Attorney General noted that this recommended treatment was continued in PSO's last rate case, PUD 201500208.

90. THE COMMISSION FURTHER FINDS that there is no need to increase base rates based on anticipated and/or unknown increases in storm damage expense in the future. The Commission finds that it is reasonable to leave the current level of storm damage expense in place. An increase in base rates is not necessary as the Company is insulated from under-recovery of storm damage expense through its tracker mechanism.

SPP Fees and Expenses

91. THE COMMISSION FURTHER FINDS that the Attorney General and OIEC both recommended adjustments to reduce the level of SPP fees and expenses requested by the Company. (Farrar Rev. Req. Resp. Test. at 27:6-14; Garrett Rev. Req. Resp. Test. at 66:7-11.) Mr. Farrar testified that the Company did not support the increase in the SPP Schedule 9 NITS (Network Integration Transmission Service) charges for affiliates. (Farrar Rev. Req. Resp. Test. at 26:9.) Under cross-examination, Mr. Hamlett of AEP admitted that these cost increases were not effective within the six-month post-test year end date. (10/30/17 Early P.M. Tr. at 69:10-19.) PUD also testified that the effective date of the requested increase in Schedule 9 NITS transmission expense was not effective within the test year or the six-month post-test year period. (Nov. 7, 2017 Tr. at KA100.)

92. THE COMMISSION FURTHER FINDS and adopts the Attorney General's adjustment to reduce the SPP Schedule 9 NITS charges by $13,994,625.

Generation O & M Normalization

93. THE COMMISSION FURTHER FINDS that PSO proposed an adjustment to normalize generation O&M expenses by using a three-year average of the expenses, adjusted to remove the costs for the retired Northeastern Unit 4. (Slater Dir. Test. at 11:3-5.) Mr. Farrar and Mr. Garrett recommended the rejection of this adjustment. (Farrar Rev. Req. Resp. Test. at 25:5-7; Garrett Rev. Req. Resp. Test. at 60:7-9.) Mr. Farrar testified that the expense had been declining during the period in question and for that reason a normalization adjustment was not indicated. (Farrar Rev. Req. Resp. Test. at 24:14-25:2.) The O&M expense has been declining in recent years, which would indicate that the test year level is appropriate for recovery in this instance. OIEC also argued that PSO did not provide any support to justify a normalization adjustment.

94. THE COMMISSION FURTHER FINDS and rejects PSO's adjustment to normalize this generation expenses. The Commission adopts the recommendation of the Attorney General and OIEC and rejects an increase of $2,110,317 to the test year production O&M.

Ad Valorem Taxes

95. THE COMMISSION FURTHER FINDS that PUD and the Attorney General recommended an adjustment to current Property/Ad Valorem Taxes to reflect PUD's recommended adjustments to the net plant in service as of the six-month post test year, June 30, 2017, resulting in a decrease of ($49,673).

Rate Case Expense

96. THE COMMISSION FURTHER FINDS that PSO has requested recovery of its incremental estimated cost for this proceeding of $1,071,350; $300,000 of Independent Evaluator expenses granted in Cause No. PUD 201600300; and a true up over-recovery of ($210,284) from prior base rate cases (Cause Nos. PUD 201300217, PUD 201500208). These three items total $1,161,066 which PSO proposed to recover over a two-year period with an annual cost-of-service amount of $580,533. (Hamlett Rebuttal, p. 50, lines 17-22.)

97. THE COMMISSION FURTHER FINDS that OIEC was the only party to present a witness that took issue with PSO's rate case expense request. Mr. Mark Garrett had a two-part recommendation wherein he recommended a reduction in PSO's recovery of costs for the current proceeding from $1,161,066 to $590,566, a reduction of almost fifty percent. (Mark Garrett Responsive, p. 51, lines 14-17.) Mr. Garrett testified that the rate case costs were overstated due to what he considered to be excessive outside legal fees; above market fees for PSO's return on equity witness; the cost of the demolition study; and the estimate for notice cost of $43,500. Second, he recommended a four-year recovery period rather than a two-year recovery period requested by PSO. (Mark Garrett Responsive, p. 51, lines 17-20.)

98. THE COMMISSION FURTHER FINDS that the evidence showed the actual expenses for outside counsel in PUD 201300217, which was a settled case, totaled $306,406 as compared to $619,690 for a fully litigated case over an extended period of time in Cause PUD

201500208. The estimate in the current case is between those two actual amounts. The estimate for the ROE witness of $150,000 is consistent with the actual cost incurred by PSO in Cause No. PUD 201500208 of $147,530. Regarding the notice, PSO's actual charges in Cause Nos. PUD 201300217 and PUD 201500208 were $30,842 and $43,531 respectively, which is consistent with the current estimate of $43,500. (Hamlett Rebuttal, p. 52, lines 2-14.) No party contested the actual expenses incurred from the previous two cases.

99. THE COMMISSION FURTHER FINDS that rate case expense costs should be scrutinized more closely than they have been in the past. Moreover, utilities should understand that not all rate case costs should be borne by ratepayers. Necessary and reasonable costs to process a rate case should be borne by ratepayers. Ratepayers should not be burdened with unreasonably inflated legal costs and expert witness fees, especially when the testimony of some expert witnesses may appear to be duplicative and/or unnecessary testimony.

100. THE COMMISSION FURTHER FINDS that rate case expense costs related to relitigation of previously settled issues shall be reviewed by PUD. PUD shall provide testimony as to specific testimony offered by an expert witness as to any new evidence not presented in previous rate cases and any change of circumstances.

101. THE COMMISSION FURTHER FINDS that two rate case expenses in the current rate case proceeding call for separate consideration. First, Mr. Meehan acknowledged in sworn testimony that his work on decommissioning in this case involved only an update to prior studies, not a full study. (11/3/17 Early P.M. Tr. at 81:16-25.) Yet the rate case expense for Mr. Meehan remains quite high and seems to indicate an expense for a full study. (Exhibit MG-2.7.) Ratepayers should not pay the expense of a full study when the actual product is an update of a previous study. Secondly, the ALJ (not a party) recommends the disallowance of witness fees for PSO witness Quackenbush. The ALJ offers this witness as an example of an expert witness that offered unnecessary testimony that contributed no value to the proceedings. Mr. Quackenbush provided a mere five pages of testimony filed on October 11, 2017. Such testimony contained no workpapers, empirical analysis or independent financial analysis. (10/30/17 A.M. Tr. at 119:10-124:18). PSO did not rely upon this witness as to any issue as is evidenced by a lack of even a mention of this witness's testimony in PSO's filed proposed findings of fact and conclusions of law.

102. THE COMMISSION FURTHER FINDS that although various parties have recommended a three or four-year amortization, the Commission will proceed with a two-year amortization that reflects the current timing of rate case filings. If rate cases continue to be brought every two years then a longer amortization will result in excessive overlap of rate case expenses.

103. THE COMMISSION FURTHER FINDS that the Company's requested costs for legal fees, witnesses, notice, and other rate case expenses be allowed. However, the Commission directs that witness fees and expenses of witness Quackenbush, an unnecessary witness that contributed nothing of substance to these proceedings, not be paid by customers but by shareholders. The Commission directs that the Company's overall rate case expenses be collected over a two-year period.

Depreciation

104. THE COMMISSION FURTHER FINDS that some parties raised a number of issues pertaining to the lack of credibility of PSO witness Mr. Spanos's data and study. Attorney General witness Mr. Dunkel testified that for Account 367 Underground Conductors and Devices, Mr. Spanos made undisclosed changes to what is supposed to be the historic data, which records how long investments have actually lived in the past. Chart 3 on page 32 of Mr. Dunkel's responsive testimony shows the difference in the data through the year 2014 used by Mr. Spanos in this proceeding compared to the data through the year 2014 used by Mr. Spanos in the prior PSO rate case proceeding. Not only did Mr. Spanos change the historic data, but he did not disclose that he had altered it. (11/3/17 Early P.M. Tr. at 6:18-20; 11/3/17 A.M. Tr. at 80:10-14). Such changes to historical data is not typical and should be disclosed by expert witnesses. Discussing Mr. Spanos's undisclosed change in data in Account 367, OIEC witness David Garrett stated, "[f]ortunately for all of us, there was a witness in this case, Mr. Dunkel, that did catch that." (11/3/17 A.M. Tr. at 62:19-22).

105. THE COMMISSION FURTHER FINDS that it is clear that PSO's witness Mr. Spanos made changes to the historic data in Account 367 and did not disclose these unusual changes. It is also clear that Mr. Spanos did not disclose that he had altered the data until the Attorney General had discovered the alteration and asked about it in discovery. The record shows that the difference between a 65 year average service life, which is what Mr. Spanos recommended in the prior case before altering the data, and the 45 year average service life Mr. Spanos recommends in this case after altering the data, is in excess of $4 million per year. (Dunkel Resp. Test. at 33). Additionally, there were irregularites in Mr. Spanos's cited rates approved in prior proceedings as well as the industry range of lives used. (11/3/17 A.M. Tr. at 102:6-24 and 11/3/17 Late P.M. Tr. at 25:8-17; Hearing Exhibit 49).

106. THE COMMISSION FURTHER FINDS that the depreciation study proposed by PSO is rejected. Furthermore, the Commission adopts the Attorney General's life and Iowa curve combination recommendations.

107. THE COMMISSION FURTHER FINDS that the Attorney General's total demolition cost estimates are reasonable and appropriate and therefore adopt them in this Cause. Furthermore, the Commission rejects Mr. Spanos's escalation of the production plant demolition cost estimates.

108. THE COMMISSION FURTHER FINDS that the Attorney General witness Mr. Dunkel used the same net salvage method the Commission had adopted in the 2008 PSO rate case. In that proceeding, the Commission adopted the Attorney General's proposed depreciation rates, which used the average of net salvage dollar amounts from recent years. (11/3/17 Late P.M. Tr. at 71:13-72:8; 11/3/17 Late P.M. Tr. at 89:7-92:2).

109. THE COMMISSION FURTHER FINDS that, based upon the record of this Cause, the depreciation rates and associated parameters recommended by the Attorney General are adopted.

110. THE COMMISSION FURTHER FINDS that at the request of PSO, Mr. Spanos did not include Account 303 in his depreciation study. (11/3/17 A.M. Tr. at 69:10-14, 70:8-9.). Because it was not part of the depreciation study, the Attorney General did not address Account 303. However, OIEC witness Mr. David Garrett did. On pages 46 through 49 of Mr. Garrett's responsive testimony on depreciation, Mr. Garrett stated that this account includes PSO's software. He recommended a 10-year amortization period instead of the 5-year amortization period PSO proposed. Mr. Garrett's analysis was clear and convincing. Mr. Garrett testified that his recommendation reduces PSO's depreciation expense by $4,993,173 per year. Based upon the evidence in the record, the Commission accepts the recommendation of Mr. David Garrett pertaining to Account 303.

Base Revenue

111. THE COMMISSION FURTHER FINDS that the Attorney General's witness, Mr. Farrar, recommended that PSO's base revenue be updated to June 30, 2017. (Farrar Rev. Req. Resp. Test. at 12:11). Mr. Farrar based his recommendation on information provided by PSO, adopted for consistency with PSO's test year-end annualized base revenue. (Farrar Rev. Req. Resp. Test. at 12:14-13:21). PSO had provided three different base revenue update adjustments that were inconsistent with the methodology originally used by the Company. (11/8/17 Early P.M. Tr. at 81:25-87:7). The Company at one point stated that its update was an estimate. (11/8/17 Early P.M. Tr. at 85:22-86:1). The final adjustment produced by the Company was provided two weeks before the beginning of the hearing on the merits, and therefore was un-vetted by the parties to this Cause. (11/8/17 Early P.M. Tr. at 87:4-14). Therefore, the Commission adopts the Attorney General's recommended adjustment to update non-fuel base revenue to June 30, 2017, which increases base revenue by $505,152 be adopted by the Commission.

Energy Efficiency/Demand Response

112. THE COMMISSION FURTHER FINDS that PUD witness, Ms. Champion, recommended that PSO's adjustment to reduce revenue for energy efficiency programs be rejected. (Champion Rev. Req. Resp. Test. at 9:3-6). Ms. Champion stated that, in effect, PSO had adjusted the revenue reduction a full year outside the test year. (Champion Rev. Req. Resp. Test. at 9:11-14). Ms. Champion testified that PSO would not be denied the lost net revenue recovery for the January through June period if PSO's adjustment is denied. (Champion Rev. Req. Resp. Test. at 13:13-20). Therefore the Commission adopts PUD's recommendation that PSO's projected revenue loss be rejected, and that PSO's adjusted revenue be increased by $2,707,619.

Elimination of SRR and AMI Riders

113. THE COMMISSION FURTHER FINDS that PSO proposed the elimination of two riders, the System Reliability Rider and the Advanced Meter Infrastructure Rider. (Champion Rate Design Resp. Test. at 8:1-4.) Moving the recovery of these costs to base rates will be revenue neutral for both the Company and ratepayers. No party challenged those calculations, which move $23,790,724 from riders to base rates, as noted in the accounting exhibit. Therefore, these two riders are moved from riders to base rates as proposed by PSO.

Fuel Procurement and Handling Expense

114. THE COMMISSION FURTHER FINDS that the Attorney General recommended moving PSO's fuel procurement, unloading and handling (fuel handling) costs out of the FCA and into base rates. PSO witness Fate stated that fuel handling costs were included in base rates until May 2015 when they were moved to the FCA to comply with Order No. 639314 issued in Cause No. PUD 201300217. The change was initially recommended by PUD and was agreed to by all parties who signed a stipulation in that case which included the AG's office. (Fate Rebuttal, COS, p. 9, lines 12-17.)

115. THE COMMISSION FURTHER FINDS that Mr. Fate testified that PSO's test year fuel handling costs in Cause No. PUD 201300217 were approximately \$4.8 million as compared to \$3.2 million in this cause. If fuel handling costs were still recovered in base rates, customers would not have realized the \$1.6 million decrease that occurred between the 2013 case and current rate case. (Fate Rebuttal, COS, p. 10, lines 5-7.)

116. THE COMMISSION FURTHER FINDS that the fuel handling costs shall remain in the FCA as this Commission has determined that all fuel costs should be in the FCA and not in base rates.

Off System Sales

117. THE COMMISSION FURTHER FINDS that currently Off System Sales ("OSS") allows for PSO's retention of 10 percent of OSS margins while sharing 90 percent of OSS margins with customers. (Hakimi rebuttal p. 3 ln 5-8).

118. THE COMMISSION FURTHER FINDS that OIEC recommends modification of PSO's FCA rider to exclude net revenues earned from SPP energy sales from the margin sharing provision that currently applies to off system sales. (Exhibit 118, pp. 14-15). The AG recommends no sharing of off-system sales so that 100 percent of any off-system sales margins will be credited to PSO ratepayers. (Exhibit 119, p. 3). Both the Attorney General and OIEC testify that the SPP Integrated Market Place now handles dispatch of units within the region and that the market rates provided by the SPP Integrated Market Place allow for an accurate check to the costs accrued by PSO. (See Exhibit 119, p. 3 and Exhibit 118, p. 14). Also, the Attorney General notes that neither OG&E nor the Empire District Electric Company gain a return on OSS in their respective fuel adjustment clauses. OG&E ended its off system sales on electricity rider as part of the settlement in OG&E's 2011 rate case. (Exhibit 119, p. 7). PUD supported OIEC's position. (Rush, Rate Design Rebuttal, p. 12, line 4).

119. THE COMMISSION FURTHER FINDS that PSO offered testimony that AEPSC's Commercial Operations, on behalf of PSO, optimizes the value of PSO's generation by participating in both the SPP Integrated Market Place Energy markets and the Operating Reserve markets. The optimization strategy extends beyond PSO's participation in SPP Integrated Market Place day ahead and real-time markets. (Hakimi Rebuttal, p. 6, lines 1-11). The SPP is tasked first with maintaining reliability, and then with matching generation supply with load demand based on market prices. According to PSO, the Attorney General's description of the SPP Integrated Market Place severely over stated the role of SPP in regards to the optimization

of PSO's OSS margins, while at the same time failed to recognize the major role of AEPSC and PSO personnel in all phases of the SPP Integrated Market Place. PSO offered testimony that keeping the OSS margin sharing in place will continue to provide incentives to PSO to maintain and operate its generating fleet so it will take full advantage of the market for the benefit of its customers. (Hakimi Rebuttal, p. 4, lines 7-16).

120. THE COMMISSION FURTHER FINDS that the volume of information that has to be submitted to the SPP Integrated Market Place and retrieved after the market has cleared has increased significantly. Participation in the SPP Integrated Market Place has lead to significantly more labor required to prepare the bids and assess the results so that PSO can be ready to implement the market results. In addition to the day-ahead energy market that did not previously exist, there are four new markets for the ancillary services in the day-ahead and the real-time markets. For the day-ahead market alone, eighty-eight (88) data points have to be submitted to SPP for each generating unit for a given day. (Hakimi Rebuttal, p. 8, lines 10-19).

121. THE COMMISSION FURTHER FINDS that the current OSS margin sharing of 90 percent to the customer and 10 percent to PSO should continue. It is clear that the advent of the SPP Integrated Market Place has changed the way PSO operates its system but it has also brought more complexity to the transactions which currently make up OSS activity. Additionally, the current OSS sharing will continue to emphasize aggressive pursuit of off-system sales for the benefit of both customers and the company.

<u>Fuel Adjustment Clause</u>

122. THE COMMISSION FURTHER FINDS that OIEC recommended certain revisions to PSO's FCA Rider to include an annual filing by PSO and provisions for notice and a hearing if requested by a party. (Norwood Responsive, p. 6, line 16 – p. 7, line 2). OIEC further recommended that the monthly fuel reports be provided electronically to all parties who have participated in PSO's most recent base rate proceeding at the same time the reports are provided to the PUD staff and that the current provision that allows PSO to make interim adjustments to the FCA factor be eliminated. (Norwood Responsive, p. 7, lines 2-9).

123. THE COMMISSION FINDS that PSO, via sworn testimony, agreed to make the same information that is provided to PUD for a proposed fuel factor adjustment available to other parties. Additionally, whenever PSO makes a decision to propose a new fuel factor, at the same time PSO notifies PUD, PSO will notify those parties that have expressed an interest and make arrangements for them to come on site to review the confidential information. (Tr. 11/8 PM, SJ6, lines 16-24). PSO is willing to change the annual fuel factor determination from November to October. PSO was also willing to send the monthly fuel letter to interested parties at the same time it is sent to PUD. (Tr. 11/8 PM, SJ4, lines 21-22). The Commission's expectation is that PSO abide by this agreement made via sworn testimony.

124. THE COMMISSION FURTHER FINDS that the current review process should be kept in place and not require the opening of a formal docket with possible additional hearings. PSO's agreement to supply both the monthly fuel letter and the information on fuel factor changes (both the annual and any interim fuel factor) to requesting parties is reasonable and should supply interested parties with the information that they need. Opening a formal docket

for setting a fuel factor is not merited. The Commission declines to adopt OIEC's proposed revisions to PSO's FCA Rider.

SPPTC Tariff Modifications

125. THE COMMISSION FURTHER FINDS that OIEC proposed three modifications to PSO's existing Southwest Power Pool Cost Tracker ("SPPTC") tariff. The three proposed modifications are summarized as follows:

A. First: OIEC witness, Mr. Norwood, recommended that annual revisions to the SPPTC tariff be made subject to review and approval by this Commission. (Exhibit 118, p. 18). Mr. Norwood recommended that PSO file an application to revise the SPPTC each year sixty days prior to the first billing cycle in October when the proposed rates are expected to be placed in effect. (*Id.*).

B. Second: Mr. Norwood's second proposed modification to the SPPTC tariff would make it explicit that the Company has an ongoing obligation to provide support for the reasonableness of third party charges recovered through the SPPTC in future base rate proceedings. (*Id.* at 19).

C. Third: Mr. Norwood's third proposed modification to the SPPTC tariff is to eliminate the provision in the SPPTC tariff authorizing interim adjustments at any time when an over or under recovery of expenses exceeds 10 percent since the SPPTC tariff already provides for addressing over and under recoveries of SPPTC costs in a future base rate proceeding. (*Id.* at 20).

126. THE COMMISSION FURTHER FINDS that PSO agreed to Mr. Norwood's second revision which was to require PSO to provide testimony in every base rate case addressing the reasonableness of the third-party charges recovered through the SPPTC Tariff. (Fate Rebuttal, p. 8, lines 10-12). PUD witness Chaplin agreed with Mr. Norwood's second recommendation that the Company has an ongoing obligation to provide testimony to address the reasonableness of third party charges recovered through the SPPTC and future base rate proceedings. (Chaplin Rebuttal, p. 6, lines 8-10). The Commission, therefore, adopts Mr. Norwood's second proposed modification to the SPPTC tariff.

127. THE COMMISSION FURTHER FINDS that PUD testified that Mr. Norwood's first proposed modification to the SPPTC, requiring the Company to file an application with the OCC to revise the SPPTC tariff each year, should not be adopted because PSO's current annual redetermination process provides for an adequate level of review. (Chaplin rebuttal p. 5 ln 16-p.6 ln 6). Furthermore, PUD testified that Mr. Norwood's third proposed modification to the SPPTC, to eliminate the current provision for the Company to implement interim adjustments to the SPPTC tariff at any time when an over-recovery or under-recovery of expenses exceeds 10 percent, should not be adopted because the 10 percent over-under provision, the annual re-determination process, and reviews in future base rate proceedings provide reasonable protections to customers by allowing multiple opportunities for review, not just review in future rate proceedings. Additionally, PSO provided agreement via sworn testimony to timely share the

SPPTC information that is provided to PUD for review to interested parties. For these reasons the Commission rejects Mr. Norwood's first and third proposed modifications to the SPPTC.

128. THE COMMISSION FINDS that PSO has added to the SPPTC that would require broader review if annual increase exceeds 50 percent. OIEC requests the Commission not adopt this added provision. This issue was litigated in the previous PSO rate case. PUD witness Mr. Chaplin testified that this added provision provides another mechanism for PUD to ensure customer protection while also incentivizing PSO to continually pursue cost control within the SPP organizational structure. (Chaplin rebuttal p. 8 ln. 18- p.9). The Commission confirms its previous decision on this specific issue and further, in this Cause, again adopts this added provision.

Tax Adjustment Rider

129. THE COMMISSION FURTHER FINDS that PSO requested that the Tax Adjustment ("TA") Rider be modified to include an ad valorem tax adjustment factor that would be adjusted annually to account for the difference in ad valorem property taxes expensed above or below the amount included in base rates. The ad valorem tax adjustment would be allocated to ratepayers in the same manner as ad valorem taxes are currently being recovered from ratepayers through base rates and recovered on a kwh basis (Jackson Direct Test. at 22:10-18).

130. THE COMMISSION FURTHER FINDS that the AG witness, Mr. Bohrmann, recommended that the Commission reject the Company's proposed change to its TA Rider for several reasons. First, PSO's proposed change to its TA Rider does not pass the well-established three-prong test used to determine whether a cost should be eligible for recovery through an adjustment mechanism outside of base rates. Mr. Bohrmann explained that property (ad valorem) taxes are 1) not substantial; 2) not volatile; and 3) within PSO's control (Bohrmann Rate Design Resp. Test. at 13:1-4). Mr. Bohrmann also identified three structural flaws with the Company's proposed change to its TA Rider. First, he explained that the proposed change only examines the change in one specific cost type - property (ad valorem) taxes - without examining the extent to which all of the Company's costs recovered through base rates may change. Second, he noted that the proposed change does not consider the impact that growth in customers, energy, and demand between rate cases will have on base rate revenues. Third, he testified that the Company's proposal shifts the risk of changes to property (ad valorem) tax paid between rate cases from PSO to the ratepayers, and offers nothing in return to the ratepayers for assuming this risk, such as a lower return on equity (Bohrmann Rate Design Resp. Test. at 15:14-21).

131. THE COMMISSION FURTHER FINDS that the DOD/FEA Witness, Mr. Blank, stated two concerns regarding the Company's proposed change to its TA Rider. First, this proposed adjustment mechanism is very different than the currently approved items in the TA rider. The TA rider is currently limited to taxes on gross revenue and the production, transmission, or sale of electric energy. In other words, these are gross receipts taxes and/or per-unit (kWh) taxes that do not vary with rate base and underlying cost of electric service. Second, Mr. Blank indicated that the Company's proposed change to its TA Rider would constitute single issue ratemaking (Blank Rate Design Resp. Test. at 9:11-11:9).

132. THE COMMISSION FURTHER FINDS that the PUD Witness, Mr. Walkup, expressed two concerns regarding the Company's proposed change to its TA Rider. First, Mr. Walkup stated that this regulatory treatment would result in single issue ratemaking if the incremental property ad valorem taxes paid is recovered from ratepayers as a rider and reviewed separately from the rate case in which multiple parties intervene. Second, this proposed regulatory treatment would reduce the Company's incentive to negotiate with the Oklahoma Tax Commission to reduce or minimize PSO's ad valorem taxes paid (Walkup Rate Design Resp. Test. at 18:8-13).

133. THE COMMISSION FURTHER FINDS that the rationale provided by the Attorney General's Office, the PUD, and DOD/FEA is persuasive. The Company's proposal to modify its TA Rider to include property (ad valorem) taxes is denied.

Federal Tax Legislation

134. THE COMMISSION FURTHER FINDS that rates are to be fair, just and reasonable. Okla. Const. art. 9, § 18; *Valliant Tel. Co. v. Corporation Commission*, 1982 OK 159, ¶¶ 7, 18, 656 P.2d 273, 275. Moreover, the Commission has a duty to safeguard the public's interest with regard to utility rates and to ensure that the rates charged by the utility are the lowest, reasonable rates. 17 O.S. § 152; *State v. Oklahoma Gas & Electric Co.*, 1975 OK 40, ¶ 20, 56 P.2d 887, 81. Moreover, ratemaking proceedings are legislative in nature, in which the Commission is granted broad discretion in arriving at a rate that is fair to both the utility and its ratepayers:

> Rate making proceedings are legislative and, since the establishment of a rate is not a matter of exact science or capable of precise mathematical calculations, broad, general, equitable principles must govern in the establishment of a rate.

Community Nat. Gas Co. v. Corp. Comm'n of Okl., 1938 OK 51, 76 P.2d 393, 394, syl. 3.

135. THE COMMISSION FURTHER FINDS that at the hearing on the merits, Commissioner Anthony asked OIEC witness Mark Garrett as well as PSO witness Randy Hamlett several questions related to pending federal tax reform. (11/6/17 Early P.M. Tr. at 40:21-41:16, 72:3-18.) This issue was not presented in pre-filed testimony, nor did parties have the benefit of crafting proposals around legislation that has actually been passed to become law.

136. THE COMMISSION FURTHER FINDS that under the evidence presented, there is the potential for the enactment of tax reform legislation that could have an effective date as early as January 1, 2018, and could result in a substantial effect upon the corporate income tax rate as well as accumulated deferred income taxes. PSO's ratepayers should not be required to pay the cost of tax liability that does not exist.

137. THE COMMISSION FURTHER FINDS that steps be taken to protect the interests of customers if tax legislation is passed while deferring ultimate regulatory action to a future proceeding.

138. THE COMMISSION FURTHER FINDS that PSO be required to record a regulatory liability equal to excess ADIT and reduced ongoing tax costs related to any federal tax reform. The adjustment and regulatory treatment of this regulatory liability could be resolved in a future proceeding. This treatment would protect customer interests while allowing PSO and other interested parties to discuss appropriate action.

Cost of Service

139. THE COMMISSION FURTHER FINDS that 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 is used to determine the costs that different classes of customers impose on the PSO system. (*See* Exhibit 24.)

140. THE COMMISSION FURTHER FINDS that in its retail cost of service study, PSO proposed to change its allocation of transmission costs for retail customers from a 4CP allocation to a 12CP allocation. (Exhibit 24, pp. 13-14.)

141. THE COMMISSION FURTHER FINDS that OIEC recommends PSO's class cost of service study be modified to retain the four Coincident Peak (4 CP) methodology for allocation of transmission costs to PSO's retail customers, rather than changing to a 12 Coincident Peak (12 CP) methodology. (Exhibit 124, pp. 4-9.) PUD also rejects PSO's proposed 12CP method for transmission cost allocation and notes that PSO made the same request in Cause PUD 201500208 with the Commission rejecting that requested change. (Exhibit 112, pp. 16-18.)

142. THE COMMISSION FURTHER FINDS that the data demonstrates and the Commission has determined that PSO is clearly a summer peaking system for retail load. (Exhibit 124, p. 5.) This is the reason that both PSO's production costs and its transmission costs have historically been allocated using a 4CP allocation methodology. (*Id.* at 6.)

143. THE COMMISSION FURTHER FINDS that PSO's proposed transmission cost allocation is rejected and, instead, approves PSO's continued use of the 4CP allocation methodology for transmission costs.

Revenue Distribution

144. THE COMMISSION FURTHER FINDS that revenue distribution is the rate design mechanism by which the proposed change in revenue requirement is assigned to the customer classes. For this case, PSO's revenue distribution proposal follows the revenue distribution recommendation from the final order in PSO's most recent rate case, Cause No. PUD 201500208, to assign the total revenue requirement change to the retail rate classes. PSO proposes to move its major retail rate classes to its required cost to serve.

145. THE COMMISSION FURTHER FINDS and adopts PSO's recommended revenue distribution and finds that establishing rates based on the utility's cost of service produces equitable rates that reflect cost causation, send proper price signals and minimize price distortions.

Respectfully submitted,

Mary Candler

MARY CANDLER
Administrative Law Judge

12/11/17
Date

C:
Commissioner Murphy
Commissioner Hiett
Commissioner Anthony
Teryl Williams
Nicole King
Joseph Briley
Maribeth D. Snapp
James Myles
Elizabeth A.P. Cates
Matt Mullins

ATTACHMENT "A"

TESTIMONY SUMMARIES

DIRECT TESTIMONY

Public Service Company

MICHAEL J. VILBERT

Michael J. Vilbert, Principal of The Brattle Group ("Brattle"), an economic, environmental and management consulting firm testified on behalf of PSO.

Dr. Vilbert testified that to estimate the Company's cost of capital, he analyzed a sample of electric utilities identified as being in the same line of business as PSO, specifically the regulated electric utility business. He estimated the ROE for each sample company using both the discounted cash flow ("DCF") and the risk positioning approaches. The risk positioning approach consists of analyses based upon the Capital Asset Pricing Model ("CAPM") and the Empirical CAPM ("ECAPM"). He also provided estimates based upon the risk premium approach. The ROE estimates from both models are then adjusted for differences in financial risk among the sample companies as well as for PSO.

Dr. Vilbert testified that the result of this process is a sample average cost of equity as if the sample's average market-value capital structure had been one with a 48.5 percent equity ratio, which is the equity ratio PSO has proposed in this proceeding. This procedure results in an ROE that is consistent with both the financial risk inherent in the Company's proposed capital structure and the market-determined information on the sample's average overall cost of capital. Dr. Vilbert's Appendix B provides more discussion on the technical details of the ROE estimation models and procedure.

According to Dr. Vilbert, the sample ROE estimates range from a low of 9.1 percent to a high of 10.9 percent, but he believed that the estimates at the lower end of the range are not reliable because they do not consider the effect of the ongoing uncertainty in the financial markets and the downward pressure on the risk-free interest rate. Conversely, the estimates at the upper end of the range reflect the adjustment for the ongoing uncertainty in the capital market and are more reliable. Therefore, for an electric utility company of average business risk and with an equity ratio of approximately 48.5 percent, the best estimate of the range for the cost of equity is from 9¾ percent to 10¼ percent. To be conservative, he set the top of the range at 10¼ percent, but for higher risk companies, the top of the range could be as high as 10¾ percent.

Dr. Vilbert recommends that the Company be allowed an ROE of 10 percent on the equity-financed portion of its rate base. This is at the midpoint of the range of 9¾ percent to 10¼ percent that he believes is reasonable for electric utilities of PSO's financial and business risk.

Dr. Vilbert further testified that during times of economic uncertainty such as now, maintaining a strong credit rating is important to ensure access to capital markets at a reasonable cost. Credit rating agencies focus on cash flow, so regulatory policies that permit a regulated utility to recover its costs in a timely manner strengthen the utility's credit metrics. Conversely, regulatory decisions denying a regulated company full recovery of its costs or unduly delaying recovery weaken the credit metrics. Other regulators—including but not limited to those in Indiana, Colorado, Kentucky, Oregon, Alabama, and West Virginia—have recognized the importance of providing fair recovery mechanisms for electric utilities' stranded costs.

According to Dr. Vilbert, the development of credit ratings and generic financial strength is important because debt investors, as well as equity investors, are concerned about the financial strength of companies such as PSO. As a result of the 2008-2009 financial crisis, creditors have become increasingly concerned about anything that adversely affects cash flow or increases leverage. For a regulated entity such as PSO, financial strength is highly dependent upon the regulatory policy to which it is subjected. Because credit rating agencies focus on cash flow, they follow developments that affect PSO's cash flow such as determinations to reduce or disallow operations and maintenance ("O&M") or depreciation expenses. Multiple reductions or disallowances can have a major effect on the utility's ability to earn its allowed ROE even though individually each reduction may be small, because cumulatively they all reduce the earned ROE.

To a large degree, a utility's cash flow is determined by the approved revenue requirement, the magnitude of its capital expenditure program, and its real ability to earn the allowed ROE. Dr. Vilbert discussed PSO's recent financial metrics, its capital expenditure program, and the effect of any reduction in cash flow on the Company's financial metrics.

According to Dr. Vilbert, the electric industry is highly capital intensive, which means that regulated electric utilities must regularly access capital markets to acquire the funds necessary to purchase the assets needed to provide reliable service. Because PSO has a large capital expenditure program and must continue to provide reliable service, it is vital that the credit-supportive environment is maintained so that the Company can maintain its investment-grade credit rating. To meet these requirements, PSO requires a reasonable ROE as well as a fair opportunity to earn its allowed return.

Dr. Vilbert further testified that the cost of capital is higher than a mechanical implementation of the ROE estimation models may suggest. Although economic conditions have improved since the start of the crisis in about mid-2008, uncertainty remains in the capital markets due, in part, to the disappointing rate of economic growth, not only in the U.S., but also worldwide. Worries about the low interest rate outlook in Europe and Japan as well as the United Kingdom's exit from the European Union have added to the concern. In addition, long-term government bond yields, which had dropped dramatically after the 2008-2009 credit crisis to unusually low levels, remain depressed relative to both historical levels and forecasts of future interest rates.

As a result, bond yield spreads remain higher than before the credit crisis, both for riskier assets as well as for less risky investments such as investment grade-rated utility debt. Although the capital market indices have returned to or exceeded their pre-crisis levels, the recovery remains fragile in part because of the weakness and uncertainty in much of the rest of the world.

This uncertainty in the financial markets also affects the results of the estimation models, because both the risk positioning model and the DCF model are based upon the assumption that economic conditions are stable. That assumption is not currently met, so estimating the cost of capital under current conditions is more complicated than it would normally be.

Dr. Vilbert stated that because the uncertainty in financial markets affects the cost of capital for all companies, including regulated utilities such as PSO, he modified the parameters of the risk positioning model to recognize the effect of the increased volatility in the capital markets as well as the overall decline in long-term risk-free interest rates on the cost of capital. Specifically, he analyzed scenarios using two different estimates of the market risk premium ("MRP") and risk-free interest rate for use in the risk positioning model. These scenarios are discussed in more detail below. Further, given the current economic uncertainty and the downward bias it creates in the CAPM model results, he also placed substantial weight on the results of the DCF analyses in determining the range of reasonableness for the ROE.

Dr. Vilbert testified that Fitch, Moody's, and S&P agree that a key factor for PSO's credit rating is maintaining solid credit metrics with an emphasis on cash flow. Specifically, S&P notes that PSO has significant financial risk and pressures on the Company's stand-alone cash flow metrics are more in line with BBB ratings, though the relationship with its parent company, American Electric Power Company, improves the final credit opinion. All three rating agencies note that PSO has a relatively large capital expenditure program, and therefore the management of the program and recovery of its costs are important. The agencies identify the regulatory environment as an important element in determining PSO's credit rating.

Dr. Vilbert testified that the Company has not been able to earn its allowed ROE. Since 2014, PSO's achieved ROE has been over 100 basis points below its allowed ROE, as shown in **Error! Reference source not found.** below. S&P also noted this pattern that "earned returns continue to lag authorized levels."

Table 1
Achieved Return on Equity

Year	Allowed ROE	Actual ROE	Weather-Normalized ROE
2016	9.50%	8.54%	8.01%
2015	9.85%	8.62%	8.56%
2014	10.15%	8.86%	8.76%
2013	10.15%	10.73%	10.49%
2012	10.15%	12.76%	11.61%

According to Dr. Vilbert, similar to regulatory lag, when a regulator determines that some of the utility's costs should not be included in the rate base or the revenue requirement, they deny the utility the opportunity to earn a return on those costs and further harm the financial health of the company. A regulated utility should have the fair opportunity to earn its allowed return on its prudently incurred costs.

Regarding the Northeastern 4 generating plant, Dr. Vilbert testified that the Company chose to discontinue operation of the coal-fired Northeastern 4 generating plant, originally built in 1980, mainly for two unforeseen reasons. First, the significant decline in the price for natural gas over the past decade has greatly decreased the operating costs of gas-fired generation. Second, more stringent environmental regulations enacted over the past five years have increased the costs of operating coal-fired generating units.

It was Dr. Vilbert's opinion that the Company be allowed to earn a return on this investment because the investment was proved useful and beneficial to the utility's customers when it was proposed. The asset was developed prudently and included in the rate base. The reasons for its early retirement were due to environmental regulations and economic conditions outside of the utility's control.

Dr. Vilbert gave examples of what other regulators had done in a similar situation. According to Dr. Vilbert, other regulators have recognized the importance of providing fair recovery mechanisms for electric utilities' stranded costs. Here are some examples of how other jurisdictions in final orders have treated similar issues are as follows:

Indiana Michigan Power Company ("I&M")—In both Michigan and Indiana, I&M is to recover the net book value of the Tanners Creek Plant at its June 1, 2015 retirement date over the remaining 30-year useful life of I&M's Rockport Unit 1 Plant.

Kentucky Power Company—In Kentucky, Kentucky Power is to recover the coal-related retirement costs of the Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2, and other site-related retirement costs through a rider over a 25-year period. The retirement costs include the remaining book values.

Appalachian Power Company ("APCO") and Wheeling Power Company ("Wheeling")—In West Virginia, APCO and Wheeling are to recover net book values of Kanawha River, Sporn, Glen Lyn, Clinch River 3, and coal-related investments in Clinch River 1 and 2 through 2040.

Public Service of Colorado ("PSC")—In Colorado, PSC is to recover the costs of 551 MW of retiring coal-fired electric generation and removal costs through depreciation during the period 2011 to 2017.

Portland General Electric ("PGE")—In Oregon, PGE is to recover, through changes to its depreciation rates, the costs, including decommissioning, of the early closure of its Boardman Coal Plant, changing the date of recovery from 2040 to 2020.

Alabama Power Company ("APC")—In Alabama, APC is to recover future unit retirements caused by environmental regulations, including unrecovered plant assets balances and costs associated with site removal and closure. Recovery is to occur over the remaining useful lives, as established prior to the decision for retirement.

In each of these cases, the companies are permitted a full rate of return on the remaining book value during the period over which the costs are to be recovered.

Some of the most relevant examples relate to the retirement of generating stations in Nevada. In 2014, the Public Utilities Commission of Nevada decided that Nevada Power Company would be allowed to recover the costs on the $247 million net book value of the 812 MW of retiring coal-fired power stations. Similar considerations have been made for Sierra Pacific Power Company in Nevada, Pacific Gas and Electric Company in California, and Black Hills in Colorado.

Dr. Vilbert testified that the ROE allowed by the Commission does not compensate the Company for risks of stranded costs. The Company made the investment with the expectation that it would be able to recover the full costs and earn a return. Disallowing recovery on the Northeastern 4 generating unit would harm the immediate financial health of the Company. Lengthening the depreciation schedule over which the remaining asset cost is recovered would also negatively impact the Company's cash flow and financial position. Furthermore, disallowing recovery on prudent investment would indicate decreased support in the regulatory environment for similarly situated utilities in Oklahoma under the OCC jurisdiction.

BRIAN J. FRANTZ

Mr. Brian J. Frantz, Manager, Regulated Accounting, of American Electric Power Service Corporation (AEPSC), a wholly-owned subsidiary of American Electric Power, Inc. (AEP), testified on behalf of PSO.

Mr. Frantz testified that the PSO cost of service amount presented in this filing includes $63,288,003 of affiliate costs, which represents 18.5 percent of the total operations and maintenance (O&M) requested in this case. AEPSC accounts for $61,521,029 of these costs and $1,766,974 represents the amount PSO was billed from other affiliates. The AEPSC costs have been adjusted to develop a normal, ongoing level of costs billed to PSO, and as a result the affiliate costs are comparable (increased by 1 percent) to the costs included in Cause No. PUD 201500208, PSO's last rate case.

According to Mr. Frantz, AEPSC is a wholly-owned subsidiary of AEP and is the centralized service company providing, at cost, various professional support services for PSO and the other AEP affiliates. Using the service company to provide these support services allows the operating companies to concentrate their efforts on serving the immediate needs of their customers, while common processes can be performed in a centralized manner to promote efficiency and cost savings. The primary service company centers are located in Columbus, Ohio; Canton, Ohio; and Tulsa, Oklahoma. These three locations employ approximately half of the AEPSC employees, including approximately 600 in the state of Oklahoma.

Mr. Frantz further testified that AEPSC uses both benchmarking and outsourcing studies where available to review the cost of the products and services that are provided to affiliates, including PSO. AEPSC also employs many levels of oversight to ensure that its costs are billed accurately. This management oversight and controls includes, but is not limited to, internal AEPSC budget and actual cost reviews; and monthly review of the AEPSC bill by the affiliate companies.

Mr. Frantz testified that AEPSC is subject to numerous audit and reporting requirements, both as a member of the AEP Corporation for financial reporting, and as a requirement of federal and state jurisdictions. These requirements include:

- Annual AEP independent audit by Price Waterhouse Coopers (Deloitte & Touche prior to the 2017 calendar year audit);
- Audit required under the 16 Tex. Admin. Code (TAC) § 25.272, "Code of Conduct for Electric Utilities and Their Affiliates," filed every three years, showing compliance with the Texas affiliate code of conduct;
- Annual "Report of Affiliate Activities" filed with the Public Utility Commission of Texas;
- Annual Affiliate Activities report filed with the Virginia State Corporation Commission;
- FERC Form 60 which is the annual report of AEPSC financials and allocations;
- Maintenance of an AEPSC Cost Allocation Manual, which documents AEPSC's cost allocation methodologies and accounting procedures and which is required by the states of Kentucky, Ohio, Oklahoma and Arkansas; and
- Periodic audits of AEPSC accounting and billing procedures conducted by FERC staff.

According to Mr. Frantz, with FERC Order No. 667, issued December 9, 2005, FERC amended its regulations to implement the repeal of the Public Utility Holding Company Act of 1935 and adopted rules to implement the Public Utility Holding Company Act (PUHCA) of 2005. FERC continues its authority under the Federal Power Act (FPA) and states in Order No. 667 that its rate authorities and information access under the FPA "...enable the Commission to detect and disallow from jurisdictional rates any imprudently-incurred, unjust or unreasonable, or unduly discriminatory or preferential costs resulting from affiliate transactions between companies in the same holding company system." As to the use of approved Allocation Factors, FERC stated that it will "...rely on our ratemaking authority to examine these agreements or require them to be filed on an as-needed basis to determine whether the regulated utility's purchase of non-power goods and services were prudently incurred and just and reasonable." Through its rules, FERC has determined that it will not require entities that were using the SEC's "at-cost" standard for traditional centralized service companies, such as AEPSC, to switch to a "market" standard.

FERC Order No. 684, issued October 19, 2006, discusses financial accounting, reporting, and records retention requirements under the Public Utility Holding Company Act of 2005.

Mr. Frantz further testified that in that order, FERC issued a new Uniform System of Accounts (US of A) for centralized service companies, added preservation of records requirements for holding companies and centralized service companies, revised FERC Form No. 60, Annual Report of Centralized Service Companies, to provide for financial reporting consistent with the new US of A and provided for electronic filing of the revised FERC Form No. 60. The requirements of FERC Order 684 became effective January 1, 2008.

FERC states in Order 684's summary that "the final rule will provide for greater accounting transparency for centralized service company operations, and uniform records retention by holding companies and service companies subject to PUHCA 2005. This transparency will protect ratepayers from pass-through of improper service company costs."

Mr. Frantz testified that AEPSC'S billing processes did not change with the adoption of FERC Order 684.

The requirements of FERC Order 684 were already being met by AEPSC and are consistent with the SEC's previous requirements. The current processes for accumulating and billing at cost to affiliates, like PSO, are operating effectively and efficiently, and changes have not been required. Changes required by the new Service Corporation US of A were minor.

According to Mr. Frantz, on an annual basis, FERC requires the filing of FERC Form No. 60, "Annual Report of Centralized Service Companies." In addition, FERC completed an audit of AEP affiliate transactions in 2010. The primary focus of this audit was AEPSC billing and allocation processes, as well as compliance with the FERC chart of accounts and record retention requirements.

Mr. Frantz testified that benchmarking is a common method that companies use to determine how the services they provide compare with companies that provide similar services. These comparisons can relate to the cost of services provided, the efficiency of services provided, customer satisfaction, or other metrics that may be comparable between companies. The results of benchmarking studies can, in some cases, help to confirm the efficiency of the service provided. In other cases, benchmarking results can reveal that a service is provided at a lower cost by other peer companies in the study. When this occurs, benchmarking studies are especially useful in that they provide insight to best practices that can be evaluated and implemented to lower the cost of providing a service. Market comparison studies are reviews undertaken to determine whether a service could be provided at a lower cost or more efficiently by an outside company.

Mr. Frantz testified that AEPSC reviews its costs in comparison to market or third-party data.

Where information is available and it is practical to do so, AEPSC reviews, performs, or participates in benchmarking studies, cost studies, and market comparisons. Each of the AEPSC organizations discussed earlier in my testimony participates in or conducts various benchmarking or market comparison studies, as needed, to evaluate key aspects of their operations. For example, the Information Technology department may choose to focus studies on the efficiency of servers and personal computers, which comprise a large amount of their total costs. The Supply Chain department may choose to focus studies on materials management and other purchasing metrics, as these studies would correlate to their primary cost drivers. The AEPSC call centers may choose to focus studies on customer satisfaction, a critical element in their operations. Human Resources, on the other hand, may participate in studies to examine their own operations, such as benefits processing, as well as participating in broader studies to examine the appropriate pay levels for all AEP employees. In all cases, the use of benchmarking and market comparison data allows each department to gain insights into the overall efficiency of the services being provided to affiliates, including PSO. AEPSC departments also periodically review processes and procedures to look for better ways to provide service and ensure that tasks are performed efficiently for the benefit of the utility companies.

According to Mr. Frantz, approximately 66 percent of AEPSC's charges to PSO are based on employee payroll-related costs. AEP and its operating companies provide compensation to their employees that approximate median wage levels for the electric utility industry. This practice allows PSO and AEPSC to attract, retain and motivate qualified employees while not being a wage leader within the electric utility industry. The compensation section of the Human Resources department develops and maintains compensation programs for PSO and AEPSC that are market competitive, and they also conduct ongoing research and recommend changes to compensation programs as necessary. By diligently reviewing the compensation levels for both AEPSC and PSO employees, the company ensures that this significant percentage of the overall cost of the services it provides is reasonable and market competitive. The costs incurred by AEPSC and billed to PSO are necessary for PSO's operations and benefit its customers by enabling PSO to meet service obligations in an efficient, cost-effective manner.

RANDALL W. HAMLETT

Mr. Randall W. Hamlett, Director of Regulatory Accounting Services for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf o PSO.

Mr. Hamlett testified that the application Package (AP) Schedule B-01 shows a revenue deficiency of $169,667,526 on a total company pro-forma basis. According to Mr. Hamlett, the following table summarizes the results presented in PSO's AP.

Description	Schedule Reference	Total Company Pro-Forma
Rate Base	B-02	$2,527,472,526
Rate of Return	F-01	7.22%
Operating Income Requirement		$182,483,516
Pro-Forma Operating Income	B-02	$78,943,783
Operating Income Deficiency		$103,539,733
Revenue Conversion Factor		1.638671
Revenue Deficiency		$169,667,526

The Company's Oklahoma jurisdictional pro-forma rate base at December 31, 2016, is $2,526,476,472 (AP Schedule B-02, line 21, col. 7). The Oklahoma jurisdictional pro-forma operating income is $78,966,486 (AP Schedule B-02, line 22, col. 7). The resulting Oklahoma jurisdictional return earned on rate base for the adjusted test year ending December 31, 2016, is 3.13% (AP Schedule B-02, line 23, col. 7).

Mr. Hamlett testified how the company accounts for O&M storm costs. Order 564437 issued in Cause No. PUD 200800144 allows PSO to defer, as a regulatory asset or liability, the difference in actual distribution storm expense from the $2.87 million included in PSO's base rates. Final Order 581748 issued in Cause No. PUD 201000050 did not alter this accounting. Final Order 639314 issued in Cause No. PUD 201300217 did not alter this cost recovery mechanism and allowed for recovery of an estimated $18.5 million related to three significant storms that occurred in 2013. Final Order 657887 and Order 658529 Modifying Order No. 657877 issued in Cause No. PUD 201500208 did not modify the cost recovery mechanism, and continued to provide recovery of the $18.5 million including inclusion of the regulatory asset in rate base.

Mr. Hamlett testified that the Company has significantly under-recovered significant storm O&M expenses. Regarding the $18.5 million of storm expenses from previous Cause Numbers, PSO will still have $6,166,655 of unrecovered storm O&M expenses at the end of December 2017, the anticipated date of new base rates. In addition, PSO had six storms from January 2015 through January 2017 where restoration efforts' cost exceeded $1 million per storm. The sum of those restoration effort total $33,143,311 of O&M expenses through April 2017. Smaller ongoing storms are slightly over-recovered as of the end of April 2017, by approximately $350 thousand.

Mr. Hamlett testified that PSO was requesting that the two amounts be added together and amortized over four years, the same time period granted for the $18.5 million amount in Cause No. PUD 201300217. PSO was also requesting that the June 30, 2018, unamortized balance be included in rate base similar to Cause No. PUD 201500208. The amount requested to be included in cost of service is $9,827,492, which is an increase of $5,202,492 over the $4,625,000 amount included in the test year. The amount included in rate base is $3,854,154 for the remaining amount of the previously-granted $18.5 million and $29,000,397 for the new significant storms.

Mr. Hamlett further testified that PSO was requesting changes regarding O&M storm recovery that was approved in Cause No. PUD 200800144 and continued in Cause Nos. PUD 201000050, PUD 201300217 and PUD 201500208.

Over the past seven years, PSO has incurred large amounts of O&M related to various storms. The annual restoration efforts' costs have varied from a low of approximately $1 million to a high of almost $25 million. The result of this is that in two of the last three base rate cases, PSO has requested amortization recovery of past significant O&M storm costs be included in future rates. In the one case that PSO did not request additional recovery, recovery of approved past significant storms was included in cost of service. PSO believes it would be better to include an amount that includes these significant storms and allow a more concurrent recovery versus an after the fact recovery, thus matching storm costs with current customers. A seven year average of storm O&M costs is approximately $10.5 million for distribution and $700 thousand for transmission. The test year amounts for distribution was $2.87 million while transmission was $66 thousand. Thus, PSO is requesting an increase in base rates of $8.264 million to reach the average level of $11.2 million of storm O&M expenses in base rates. As in the past, any storm-related costs above or below the amount included in base rates, now requested to be $11.2 million, would be deferred as a regulatory asset or liability. Any regulatory asset or liability balance would be addressed in an appropriate future filing at the OCC. The Final Order in this proceeding should contain a finding that PSO's O&M storm costs in base rates is $11.2 million and actual incurred amounts above or below that level will be deferred into a regulatory asset or regulatory liability.

Mr. Hamlett further testified that the current practice approved by the OCC is to include an estimate of rate case expenses, amortized over an applicable time period, to be included in the base rate revenue requirement. In addition, the Commission has historically allowed PSO to defer as a regulatory asset or liability the difference in actual expenses when compared to the amount included in base rates and address the difference in PSO's next base rate filing. Any difference between the estimated amounts for this proceeding, including the independent evaluator from Cause No. PUD 201600300, would be deferred as a regulatory asset or regulatory liability.

Mr. Hamlett testified that in Order No. 657877, the Commission stated:

> The Commission finds that cost recovery should be approved through base rates for plant investment in service as of July 31, 2015, attributable to PSO's environmental compliance plan ("ECP"). The Commission finds that those plant investments not in service as of July 31, 2015, relating to PSO's Northeastern Unit 3 DCI/ACI/FF investment and PSO's Comanche Dry Low NOx Burners investments should receive deferred accounting treatment for depreciation, property tax and a weighted average cost of capital return on such investment once the investments are placed in service. The Commission finds that the deferred accounting regulatory asset resulting from reasonable investments shall be included in rate base in PSO's next base rate proceeding. The Commission finds that PSO should be denied cost recovery for the accelerated depreciation that PSO seeks to recover for Northeastern Units 3 and 4 over the 2016 to 2026 period and that, to mitigate rate increases, depreciation for the undepreciated, "original" costs of these two units should continue on its current pace to 2040. The Commission finds that PSO should be granted cost recovery in this proceeding for PSO's SOFA investments on Northeastern Units 3 and 4, Southwestern Unit 3, and the majority of its investments in Northeastern Unit 2 to the extent that such investments are in service as of July 31, 2015 [At page 5.]

Mr. Hamlett stated that the amount of the ECP deferrals is dependent upon the date new base rates are implemented in this proceeding. Assuming new base rates are implemented on the first billing cycle of January 2018, the ECP deferrals will total $44,559,693 as summarized in the table below.

Description	Amount
Return	$30,257,348
Depreciation	7,818,453
Property Taxes	4,237,631
Carrying Cost on Regulatory Asset	2,246,260
Total	$44,559,693

According to Mr. Hamlett, PSO is proposing to recover the deferral over the same time period that the Northeastern coal investment will be recovered. That time period is through 2040. Thus, the time period for the ECP deferral recoveries would be 2018 through 2040 or 23 years. The June 30, 2017, balance has been included in rate base in compliance with the Commission's finding in Order No. 657877.

Mr. Hamlett testified that to be in compliance with the ECP, PSO retired Northeastern Unit 4 in April 2016 utilizing standard FERC Uniform System of Accounts retirement entries. These entries debit (decreased) accumulated depreciation and credited (decreased) plant in service for the original cost of the investment. The effect of such entries is that any under-depreciated assets value of a retired investment, whether it be a pole or a power plant, resides in accumulated depreciation to be utilized in a future depreciation study that will adjust depreciation rates on a prospective basis that recognizes the remaining net amount to be depreciated in the future.

PSO is proposing to recover the remaining investments in Northeastern units 3 and 4, including the ECP investments on Unit 3, through 2040, the same date from the Commission's Order in Cause No. PUD 201500208. The depreciation rates to be applied to the Northeastern Unit 3 gross plant investment, that were calculated by PSO witness John Spanos, are designed to recover the remaining Northeastern units 3 and 4 remaining net plant through 2040.

Mr. Hamlett testified that the recovery period will require the use of regulatory asset accounting.

Since Northeastern Unit 3 is scheduled to be retired in 2026, its investment will not be fully recovered at the time it is retired. Thus, regulatory asset accounting will be required in accordance with ASC 980-340 Regulated Operations-Other Assets and Deferred Costs. Under this standard, incurred costs may be capitalized as a regulatory asset. In this case, the incurred costs would be depreciation through the retirement date of 2026 while recovery would be through 2040.

According to Mr. Hamlett, the regulatory asset should be included in rate base, just as the ECP deferrals are, and likewise should be amortized through 2040 as applicable.

Mr. Hamlett testified regarding the AMI Rider Tariff. The commission stated at page 8 of Order No. 657877: "The Commission rejects the ALJ's recommendations regarding the AMI rider and finds that the rider shall remain in effect until the first base rate case subsequent to the full implementation of AMI, consistent with the current provisions of the AMI rider tariff." Thus, the AMI rider continued and will continue until PSO's first base rate case subsequent to full implementation. Full implementation has occurred making this the subsequent first base rate case.

According to Mr. Hamlett, in the previous base rate case, PSO removed the AMI investment and expenses from base rates via pro-forma adjustments. In this case, no adjustments were made to remove the AMI investment or remove all AMI-related expenses. However, the test year was a combination of pre- and post-AMI full implementation. Thus, certain legacy system expenses were removed because they are non-recurring and certain expenses were added via pro-forma adjustments to normalize the test year expenses to an ongoing post-deployment level.

Mr. Hamlett testified that the savings related to AMI were incorporated into the test year.

Regarding the old meters that were retired due to AMI, PSO established a regulatory asset for the unrecovered net book value of the non-AMI meters in accordance with the Commission Order No. 639314 issued in Cause No. PUD 201300217. PSO has been amortizing the regulatory asset using a 9.58% depreciation rate as detailed in the Order. Finally, the net regulatory asset has been included in rate base consistent with the Order.

Mr. Hamlett testified that PSO tracked the revenues and costs on a monthly difference using over/under accounting with the difference between the revenues and costs we deferred into a regulatory asset or liability depending on the outcome of the calculations (revenues greater than costs – regulatory liability, costs greater than revenues – regulatory asset). At December 31, 2016, PSO had returned approximately $5.1 million in savings to customers through the AMI Rider with an additional $6 million scheduled to occur in 2017. Therefore, the $11 million of guaranteed AMI savings contained in Cause No. PUD 201300217 Joint Stipulation and Settlement Agreement approved in Order No. 639314, will have been returned to customers by the time new rates are implemented in this proceeding.

The over/under accounting will end when the AMI rider is discontinued and the AMI costs are included in base rates (i.e., the implementation of new rates and tariffs resulting from this case). The AMI tariff rate was recently revised with a goal of a minimal remaining balance at the end of 2017. Mr. Hamlett recommended that PSO provide the OCC staff with the final balance within 60 days of the date the AMI rider is discontinued and that the balance be transferred to the fuel over/under balance.

Mr. Hamlett further testified that PSO is requesting that the Final Order in this case recognize the amount of $35,779,771 in property (ad valorem) tax approved to be recovered through base rates in this case. PSO requests that the Tax Adjustment Rider (TA) be modified to include a property (ad valorem tax) adjustment factor that will be adjusted annually to account for an incremental amount of property (ad valorem) taxes expensed above or below the baseline amount included in base rates. PSO has modified the currently-approved TA to accommodate this proposal. The annual true-up is proposed to be the difference between the actual property (ad valorem) taxes recorded on PSO's books and records and the actual amount being recovered from revenues billed to customers. That difference is then refunded or surcharged to customers in a subsequent year.

According to Mr. Hamlett, PSO will defer, as a regulatory asset or liability, the difference in actual property (ad valorem) taxes and the amount being recovered from customers on a monthly basis. The sum of the monthly differences will become the true-up amount to be refunded or surcharged.

Mr. Hamlett testified that to serve its customers, PSO has significant investments that generate a large amount of property (ad valorem) taxes. PSO must pay the applicable taxing authorities for which the amount it pays is outside the direct control of the Company. By including property (ad valorem) taxes in the TA, PSO's customers will ultimately pay exactly what PSO pays not a penny more or a penny less. If this accounting is not adopted, the amount paid by customers will be different than the amount paid by PSO.

Mr. Hamlett testified that the adjustments made by PSO to the test year financial results are for known and measurable items included in its revenue requirement to reflect a normal, ongoing level of operations. Examples of the adjustments include the following:

- Normalization adjustments to adjust the test year data to normal ongoing levels of revenue or expense. An example of this type of adjustment is the adjustment related to pension costs to reflect the ongoing level based on the current actuarial study.

- Adjustments to book amounts to a cost of service ratemaking basis for the purpose of including items recovered in rates or eliminating items not recovered in base rates. Examples of this type of adjustment are the inclusion of interest expense to be paid on customer deposits in PSO's cost of service, which are not included in operating income on a financial reporting basis, and the removal of both the revenues received and expenses incurred in PSO's energy efficiency program. These energy efficiency program expenses and revenues are reported in operating income on a financial basis, but excluded from PSO's cost of service since they are subject to a separately-approved OCC rider and are not recovered in base rates.

- Annualization adjustments to reflect ongoing levels of revenue, expense, or capital. Examples of this type of adjustment include annualizing depreciation expense to reflect the annual effect of the depreciation rates recommended by PSO in this filing, and including in plant in service the investment incurred by PSO for projects that are currently in service or expected to be in service by June 30, 2017.

Mr. Hamlett described the components included in PSO's rate base. The rate base components included on AP Schedule B-02, 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, Cash Working Capital, Prepayments, Materials and Supplies, Fuel Inventories, Customer Deposits, Off-System Trading Deposits, Accumulated Deferred Income Taxes, Excess Deferred Taxes and pre-1971 Investment Tax Credits. The rate base schedule starts with the actual balances at December 31, 2016, with some amounts restated to reflect a thirteen-month average balance for the period of December 2015 through

December 2016. PSO determined the Cash Working Capital component on AP Schedule B-02, line 9, using a lead-lag study.

Mr. Hamlett testified that AP Schedule E-01 presents a Cash Working Capital ("CWC") allowance of a negative $110,725,044, which reduces PSO's rate base and resulting revenue requirement. CWC is an estimate of the funds supplied by investors to cover PSO's operating costs during the period before revenues are collected from customers. The allowance is quantified using a lead-lag study and recognizes that investors are entitled to earn a return on the funds they supplied to finance the day-to-day operations of the business. In this case, as in past PSO cases, the negative CWC allowance is the result of PSO minimizing the delay in collecting revenues from customers through the factoring of accounts receivable. PSO has included factoring expenses in cost of service as permitted in prior Commission orders as an offset to this negative CWC allowance.

Mr. Hamlett testified regarding the prepaid pension balance. According to Mr. Hamlett, the Prepaid Pension amount is entirely supported by actual cash contributions in excess of pension cost. Inclusion in rate base will allow recognition of the Company's cost of funds on these cash contributions. Not included in the Company's request are non-cash accrual adjustments made under ASC 715-20 (formerly FAS158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*), since such adjustments have no effect on the amount of the Company's cash pension investment or its ASC 715-30 pension cost.

These additional contributions were made to address substantial underfunding that would have continued to exist if the contributions had not been made. They do not relate to anticipating or pre-funding future obligations, but rather were made to catch up funding to the current accumulated benefit obligation. Even with these additional contributions, the Company's qualified pension plan was only 99.7 percent funded in terms of the ASC 715-30 benefit obligation at December 31, 2016. The additional pension contributions have been prudently incurred by the Company to provide service to its customers, are necessary for the provision of service, and constitute property that is used and useful in providing public utility service.

Pension cost is established by generally accepted accounting principles as set forth by the FASB. However, pension contributions are based on separate Employee Retirement Income Security Act (ERISA) requirements, so the amount of pension cost and the amount of pension cash contribution most often vary. Generally accepted accounting principles require that this difference be recorded on the balance sheet as a prepayment if contributions exceed cost or as a liability if cost exceeds contributions.

Mr. Hamlett further testified that customers benefit from the investment earnings on the additional fund assets. This has the effect of reducing pension costs under generally accepted accounting principles in an amount that grows over time through compounding. The additional pension contributions recorded as a prepaid pension asset reduced by approximately $11.9 million on a total Company basis the 2016 pension cost that the Company would have had to reflect in rates. In other words, had the Company not made the additional pension contributions, the total amount of pension cost that PSO would have to reflect in rates would be approximately $18.3 million instead of $6.4 million.

Mr. Hamlett testified that the requested prepaid pension asset treatment was consistent with the final Order's revenue requirement calculation from PSO's most recent rate case Cause No. PUD 201500208.

Mr. Hamlett supported the following additions and deductions to rate base included in PSO's filing.

OTHER ADDITIONS AND DEDUCTIONS TO RATE BASE		
Adjustment	**Increase / (Decrease)**	**Reference**
Customer Deposits (Year End)	($49,674,708)	SP WP B-06
Off-System Trading Deposits	($63,582)	SP WP B-06
Red Rock Regulatory Asset	$9,050,820	SP WP B-03-3
Deferred Storm Expense – 201300217	$3,854,154	SP WP B-03-5
SFAS 106 Medicare Subsidy	$3,919,320	SP WP B-03-6
ECP Deferrals	$30,508,931	SP WP B-03-8
Retired Meters	$50,131,107	SP WP B-03-9
ARO Retired Plant	$539,767	SP WP B-03-10
Deferred Storm Expense	$29,000,397	SP WP B-03-11
IPP System Upgrade Credits	($1,050,066)	SP WP B-03-1
Refundable CIAC	($378,434)	SP WP B-03-4
Deferred Pole Attachment Revenue	($788,015)	SP WP B-03-7
Accumulated Deferred Income Taxes (ADIT)	($1,041,1979914)	AP B-02
Excess Deferred Income Taxes	($4,937,384)	SP WP J-03
Def. Investment Tax Credit	($15,971)	AP B-02

Mr. Hamlett testified that AP Schedule H-01 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. AP Schedule H-02 provides each individual adjustment to operating income by the categories listed on AP Schedule H-01. The SP workpapers (marked as SP WP H-02-1, SP WP H-02-2, etc.) also provide supporting information on each individual adjustment.

Mr. Hamlett testified that PSO has utilized a 2040 retirement date as ordered by the OCC in Order No. 657877 issued in Cause No. PUD 2015000208. As detailed earlier, this will require deferred expense / regulatory asset accounting to recognize the difference between the 2026 retirement date and the Commission's order, which utilizes a 2040 retirement date. Therefore, PSO requests that the final order in this proceeding recognize and authorize PSO to utilize regulatory asset accounting to recognize the difference between the 2026 retirement date and the 2040 date used to set rates.

The Northeastern Unit 4 retirement entries were in accordance with the FERC USofA. Under the FERC USofA, PSO records plant in service assets at original cost by various FERC accounts on its books. Over time, PSO depreciates the assets using approved depreciation rates, which are recorded in accumulated depreciation.

Plant in Service less Accumulated Depreciation is known as Net Plant in Service. When plant is retired, the Plant In Service account is reduced by the original cost and a corresponding entry is made to accumulated depreciation. The FERC USofA states:

> B (2) When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in paragraph D, below. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property. The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation account.

According to Mr. Hamlett , for this retirement, PSO followed the FERC USofA and the book cost of Northeastern Unit 4 was credited to the appropriate electric plant account and the exact same book cost of Northeastern Unit 4 was charged to accumulated provision for depreciation (i.e., credit plant in service and debit accumulated provision for depreciation for the exact same amount).

The result is the Northeastern Unit 4 asset is no longer in plant in service. However, because Northeastern Unit 4 was not fully depreciated at the time of retirement, the amount of credits from applying approved commission depreciation rates was not large enough to cover the debit associated with the retirement entry.

This is common under FERC retirement accounting according to Mr. Hamlett. A company's assets are made up of many different assets in various FERC accounts and there are many reasons an asset is retired on a utility's books. For example, it may simply be worn out, and it is time to replace it. A new pole in service may be knocked over by an inattentive driver. A group of transmission towers may be retired due to a major ice storm, or a group of distribution poles may be retired because they are relocated as part of a major highway project. Or, as in this case, a group of assets at a power plant may be retired because the power plant will no longer generate electricity due to the cost of government regulations. Under the FERC USofA, all of these retirement entries are the same basic entry: debit Accumulated Depreciation and credit Plant in Service for the original cost. It does not matter if the individual assets are 75 years old or 2 days old. In other words, individual assets will have many different useful lives, which means that the useful life of such assets is not a known amount, but is an estimate. Over time, assets are retired and replaced, and in rate cases, depreciation rates, through a depreciation study, are adjusted and refined for what is the appropriate estimated useful life to include for this remaining group of assets. The Net Plant in Service amount is the amount that is included in rate base.

Mr. Hamlett testified that PSO requests that the Commission make the following findings of fact:

(1) PSO's total Oklahoma jurisdictional pro-forma adjusted rate base at December 31, 2016, is $2,526,476,472.
(2) PSO's Oklahoma jurisdictional pro-forma net operating income for the test year ending December 31, 2016, is $78,966,486.
(3) PSO's overall requested return on rate base is 7.22%.
(4) PSO's Oklahoma jurisdictional pro-forma base rate cost of service is $182,411,601.

SCOTT A. RITZ

Mr. Scott Ritz, Director of Customer Services & Marketing for Public Service Company of Oklahoma (PSO), testified on behalf of PSO.

Mr. Ritz testified that prior to PSO's AMI deployment, meters were manually read each month. Many conditions such as locked gates, aggressive dogs, inclement weather, and employee absences prevented timely and accurate readings from occurring. When these situations occurred, it was necessary to either request a special trip by a field agent to read the meter or to estimate the customer's monthly usage. This estimation process often created frustration for customers and complicated PSO's goal of ensuring consistently accurate billing statements. With automated meter reads, AMI nearly eliminates estimated bills, leading to greater billing accuracy, which also leads to improved customer satisfaction. For example, when a customer wishes to terminate service, the AMI meter is read remotely and a final bill is issued immediately.

According to Mr. Ritz, just prior to implementation of AMI, PSO estimated an average of 16,300 customer bills monthly, or approximately 195,000 annually. This represented approximately three percent of total bills sent to customers. During the deployment of AMI, the number of estimated meter readings declined to less than 370 estimated meter reads per month. As of 2017, the number of estimated reads continues to decline to approximately 100 per month, which represents 0.02 percent of all bills.

Mr. Ritz testified that prior to AMI, PSO had to manually disconnect and reconnect service at customers' premises. With the implementation of AMI, meters equipped with a remote service switch enable power to be turned on or off remotely. PSO has the ability to connect electric service remotely for the majority of customers, typically within minutes of a customer's request. Remote service connections help customers initiating or transferring service, requiring service connections on weekends or holidays, and/or needing quick reconnection after a service disconnect. For disconnections, service reconnections occur within minutes after payment remittance. Mr. Ritz testified this happens 24 hours a day, seven days a week—even on holidays.

Mr. Ritz further testified that call center representatives now have real-time access to meter data, which helps them immediately discuss actual usage information with customers. As an example, when a customer calls about a power outage, the real-time access allows call center representatives to determine whether the outage is due to a PSO outage or to an issue on the customer side of the meter. Before AMI, PSO sent an agent to the field to verify the outage and identify its origin. In today's ever-changing and fast-paced environment, AMI is able to deliver the types of immediate services that our customers have come to expect.

According to Mr. Ritz, prior to AMI, customers had to individually notify PSO of outage situations. Today, PSO is immediately aware of a customer's outage and can respond more rapidly and with more detail about the extent and cause of the outage. Through predictive analytics from AMI, PSO is also able to identify electrical system issues that could lead to a decreased level of power quality or even future outages for customers. This predictive information often enables PSO to make repairs or adjustments to the grid even before customers are aware a problem exists.

This reduction in potential power quality issues and outages improves the customer experience. In fact, J.D. Power and Associates reports that overall customer satisfaction increases as much as 45 points, or six percent higher, when a customer has "perfect power." Obviously, "perfect power" is an ideal state, but the ability to reduce potential power quality issues and outages certainly contributes to customers achieving that state.

Mr. Ritz also testified that with the implementation of AMI, PSO can communicate information with customers in ways that were previously unavailable. Customers now have access to the My Energy Advisor web portal, as well as the Mobile Alerts system that communicates customer-specific service and billing information.

Mr. Ritz testified that PSO is able to offer customers four new, money-saving rate plans: Direct Load Control (DLC), Time of Day (TOD), TOD + DLC Combo, and Variable Peak Pricing (VPP). Collectively, these programs are referred to as Power Hours. PSO is also able to offer Power Pay, a voluntary payment option that allows customers to pay as they go in lieu of the traditional post-pay billing. Power Hours and Power Pay, together referred to as "Consumer Programs".

According to Mr. Ritz, these programs will have a very positive affect on our customers' satisfaction. According to J.D. Power and Associates, customers place considerable value on the availability of optional rate plans with satisfaction increasing as much as 18 percent (or 113 points) when customers participate. Additionally, these offerings allow us to further engage with our customers, which drives satisfaction even higher. Awareness (as compared to unawareness) of available programs increases customer satisfaction as much as 10 percent.

Mr. Ritz testified that as discussed in Mr. Dohrmann's testimony, the programs are creating "...energy savings and demand reductions [that provide] a pathway to financial savings for program participants." ADM verified that customers enrolled in the TOD rates saved on average $26 during the peak season. For customers participating in DLC events, they received approximately $12 on average in bill credits during the summer of 2016.

While the 2016 results were positive, it is important to note that AMI was not fully deployed until July of 2016; therefore, the 2016 averages should not be viewed as the ceiling for potential customer savings. Participants in the TOD programs have the potential to save as much as 30 percent, while DLC participants can earn $40 in bill credits per thermostat. PSO is continually working to refine program methodologies and increase customer communications to assist Power Hours participants in maximizing savings.

Mr. Ritz stated that Power Pay is a voluntary payment option commonly referred to as prepay. This payment option allows customers to pay as they go in lieu of the traditional post-pay billing options.

The Commission approved the program in June 2016, and PSO tested the program with employees beginning in July 2016. After a successful testing period, PSO began offering the program to external customers in November 2016. In mid-February 2017, PSO started to formally market the program to customers through several channels, such as email campaigns, customer mailings, customer brochures, bill stuffers and videos. TV and radio advertisements were also conducted in May 2017.

PSO currently has approximately 1,500 Power Pay enrollments, with approximately 100 customers signing up per week.

According to Mr. Ritz, PSO developed a comprehensive communication and education plan to inform customers about AMI meters and how to maximize the benefits, specifically through participation in Power Hours. This plan employed several different means of communication such as (1) outreach at community events and customer meetings, (2) a tailored marketing campaign that included email and social media campaigns, and (3) radio and TV advertisements promoting the programs.

STEVEN F. BAKER

Mr. Steven F. Baker, Vice President of Distribution Operations for Public Service Company of Oklahoma (PSO or Company), testified on behalf of PSO.

Mr. Baker testified that PSO's Distribution Operations organization, which is comprised of three operating districts and three functional support departments, oversees the planning, construction, operation and maintenance of PSO's distribution system. By comprehensive and effective reliability planning, programs, and system investments, the Distribution Operations organization continues to provide 547,000 PSO customers with reliable electric system performance that compares favorably to state, regional, and national reliability averages.

PSO has invested approximately $205 million in its distribution system beyond the investment included in its last base rate proceeding (PUD 201500208). The investment supports safety, customer growth, customer satisfaction, reliability improvements, capacity planning, and engineering standards, in addition to complying with Commission rules. The distribution capital investment projects are necessary and reasonable to continue providing safe, reliable, and economic service to our customers.

PSO's adjusted test year distribution O&M expense is approximately $92.5 million, which includes an adjustment for a requested amount of severe storm amortization expense, as well as an adjustment to the annual storm cost amount. This adjusted test year expense is instrumental in supporting the Company's day-to-day distribution operations to ensure the reliable and safe delivery of power to customers.

Since PSO's last base rate case, PSO has experienced and prepared for several severe weather events, including ice, wind, and snow storms, which impacted PSO's distribution system. These events have cost nearly $30 million in O&M, for which PSO is seeking recovery in this proceeding. Additionally, the implementation of AMI throughout PSO's service territory has helped to shorten customer outage duration and reduce the overall cost of restoration efforts during these events.

Mr. Baker further testified that PSO serves approximately 547,000 customers in 232 cities and towns across 30,000 square miles of eastern and southwestern Oklahoma. This includes approximately 470,000 residential, 63,000 commercial, 6,200 industrial, and 7,800 other customers. PSO's Distribution Operations organization includes three districts: Tulsa, Lawton, and McAlester. PSO's distribution system includes approximately 15,200 overhead circuit miles and almost 4,900 underground circuit miles.

Mr. Baker discussed PSO's distribution reliability. Mr. Baker stated that PSO's SAIFI, SAIDI, and CAIDI indices excluding major events, as defined by the Oklahoma Reliability Rules, are shown in Figures 1, 2, and 3 respectively.

Figure 1

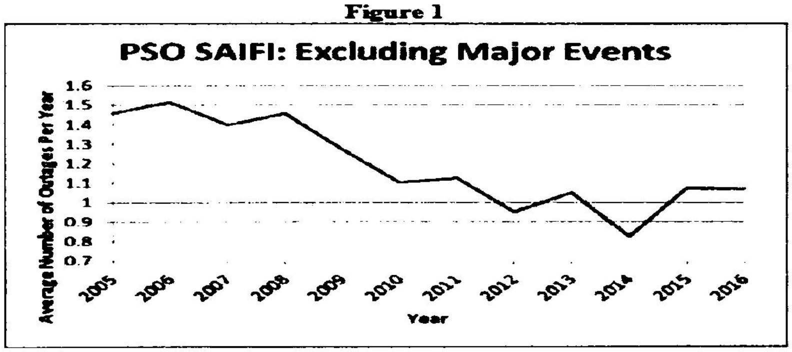


Figure 2

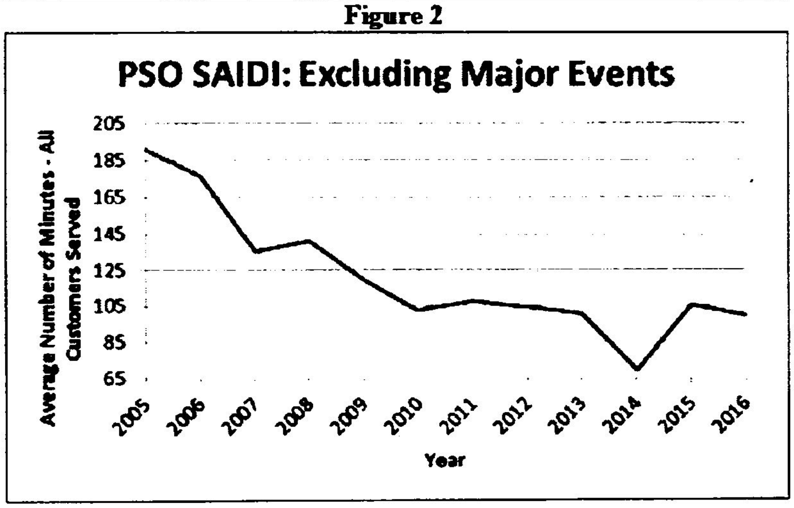
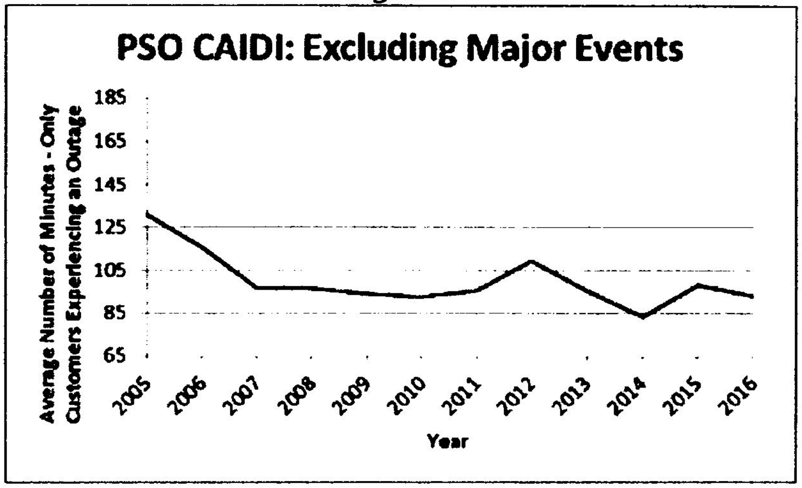


Figure 3



According to Mr. Baker, over the past eleven years, PSO's overall reliability performance has improved dramatically. Since 2005, PSO's SAIDI has improved approximately 48 percent, PSO's SAIFI has improved over 26 percent, and PSO's CAIDI has improved approximately 29 percent.

Mr. Baker testified that PSO's electric system reliability performance compares very favorably to state, regional and national averages. PSO's electric system SAIDI reliability performance is 46 percent better than the mean when compared to other Oklahoma regulated utilities for the period of 2012-2016. PSO's electric system SAIFI reliability performance is 16 percent better than the mean for this same time period.

Similarly, PSO's electric system reliability performance compares favorably on a regional basis. Based on 2015 reliability information published by the U.S. Energy Information Administration (EIA), PSO's SAIDI reliability performance is 17 percent better as compared to regional investor-owned utilities within the Texas, Kansas, Arkansas, and New Mexico regions. Using this same information, PSO's SAIDI reliability performance is 12 percent better when compared to similarly-sized (between 500,000-1,000,000 customers) national investor-owned utilities.

Regarding test year O&M expenses, Mr. Baker testified that the Company's adjusted test year O&M expenses for distribution activities were $92,462,983, which includes approximately $4.4 million associated with a severe storm amortization expense, and an additional $7.6 million to increase the average level of distribution O&M for severe storms.

According to Mr. Baker, to compare the O&M expense level for both rate cases, the adjusted distribution test year amount for the previous rate case (Cause No. PUD 201500208) must be adjusted to account for the impact of the expenses previously recovered through the System Reliability Rider (SRR). The impact of the severe storm amortization expense approved in Cause No. PUD 201300217 is also factored into the comparison of test years shown in Figure 5.

Figure 5

Test Year Comparison Items	PUD 201500208 Adjusted Test Year	2016 Adjusted Test Year (Excluding Storm Expense)
Adjusted O&M	$44,934,106	$92,462,983
SRR Adjustment	$21,725,896	
Severe Storm Amortization	$4,542,570	
Average Level of Severe Storms Increase		$7,630,000
Severe Storm Amortization		$4,392,763
AMI Meter Expense Increase		$4,373,789
Totals	**$71,202,572**	**$76,066,431**

Mr. Baker testified that the upper portion of Figure 5 shows the aforementioned SRR and severe storm amortization items, while the lower portion shows increases in the current test year over the prior test year. The increases over the prior test year include $4.4 million associated with severe storm amortization expense, and an additional $7.6 million to increase the average level of distribution O&M for severe storms.

According to Mr. Baker, PSO experienced five severe weather events, or major storms, since the last rate case, which include the following:

- January 1, 2015 – This ice storm impacted PSO's Lawton District, costing $1,409,096 in O&M. Although there were no significant outages associated with this event, the forecasted weather called for freezing rain and ice. PSO had approximately 1,175 employees and contractors ready to respond to power outages.

- May 16, 2015 – This wind storm impacted PSO's Lawton, McAlester, and Tulsa Districts, causing nearly 26,000 customer outages at the peak, and costing $1,061,079 in O&M. Over 570 PSO employees and contractors were mobilized for storm restoration efforts.

- November 27, 2015 – This ice storm impacted PSO's Lawton District, causing over 10,000 customer outages at the peak, and costing $4,256,750 in O&M. Approximately 500 PSO employees and contractors were mobilized for storm restoration efforts.

- December 26, 2015 – This snow storm impacted PSO's Lawton District, causing approximately 23,500 customer outages at the peak, and costing $7,738,424 in O&M. Approximately 900 PSO employees and contractors were mobilized for storm restoration efforts.

- July 14, 2016 – This wind storm impacted PSO's Lawton and Tulsa Districts, causing 109,000 customer outages at the peak, and costing $4,862,325 in O&M.

> Approximately 1,000 PSO employees and contractors were mobilized for storm restoration efforts.

Mr. Baker further testified that there were other weather events that were pertinent to the case. In early January of 2017, PSO prepared for a forecasted major ice storm which was ultimately predicted to impact a large percentage of PSO's service territory. On Friday, January 6, 2017, PSO began receiving early weather forecasts indicating a severe ice storm was possible during the middle of the following week. PSO continued to monitor all available weather forecasts over the weekend of January 8 and 9, while concurrently beginning preliminary preparations for a major winter weather event. By the evening of Monday, January 9, local weather forecasts, forecasts from the Norman and Tulsa offices of the Nation Weather Service, and forecasts from American Electric Power's Meteorology department were gaining confidence that a significant icing event was likely for all or portions of PSO's three operating districts starting on Wednesday, January 11. In accordance with PSO's pre-defined major event response strategy, PSO began to scale up storm preparations by taking actions such as alerting our staging area partners, inquiring about the availability and location of off-system resources, and staffing our logistical support functions.

PSO's plans call for the acquisition of additional off-system line vegetation resources to be staged throughout the service territory in advance of the start of winter precipitation (preparation for storms is described in more detail later in my testimony). PSO received the initial wave of line and vegetation resources by January 10, completed safety orientations for all workers, and assigned the off-system resources to work teams and locations in preparation for the start of a wide-spread ice storm. PSO closely monitored weather forecasts and local conditions to determine if additional off-system resources would be required. Although PSO experienced some moderate icing across a wide variety of the state and some isolated pockets of heavier icing, the storm was less severe than predicted in PSO's service territory and the number of customers that experienced outages was relatively low. However, other portions of the state were severely impacted by this weather event. Once it was clear the weather impacts to PSO's service territory would not be significant, PSO immediately began demobilizing our major storm restoration logistical and operational organizations. PSO also began releasing off-system resources to their home base or other neighboring utilities that were requesting additional workers. PSO expended $10,356,294 in preparation for this event, the vast majority of which was for mutual assistance that PSO had acquired.

Mr. Baker testified that the AMI program had provided operational and reliability benefits to PSO's customers and distribution system.

PSO has experienced a variety of benefits from AMI during both normal operations and storm restoration situations. AMI has enabled PSO to identify and correct undesirable system conditions impacting thousands of customers such as low voltage, high voltage, intermittent outages, and identify pending equipment failures such as damaged distribution transformers and overheated meters/meter enclosures before a customer experiences an outage. AMI provides near real-time notification of outages down to the individual customer level without relying upon customers to report an outage to our call centers. AMI allows PSO to monitor and spot check voltage levels at over 540,000 locations across our system, which pinpoints areas requiring immediate attention or longer-term capacity planning needs. AMI allows PSO to selectively "poll" meters remotely to check for voltage and proper meter function without dispatching an employee to the field. PSO has also realized a reduction in outage restoration time during major storm restoration situations stemming from the AMI.

Mr. Baker testified that the two-way communications capabilities of AMI allow PSO to achieve improved customer reliability by alerting PSO to potential reliability issues. In 2016, PSO proactively responded to the following potential customer reliability issues:

- Temperature Alarms: PSO identified 626 events where there was a temperature alarm. Identifying potential high temperatures in the meter enclosure confers the ability to investigate and proactively correct issues. Of these events 453 problems were found, avoiding a potential issue or outage, and 173 no issues were found.

- Voltage Interval Reading Capability: In 2016, 2,073 meter locations were investigated where the meters were reporting multiple events due to a momentary loss of voltage or low voltage. Over one-third of the locations were proactively repaired, which prevented a customer outage and mitigated the need for the customer to contact PSO. The following is the breakdown of these events:

Voltage Interval Reading Metrics	Count
Service connections repaired	788
Diversions identified	390
Vandalism	60
Issue in the meter enclosure	265
Stolen meter	95
Electrician	103
No issues	284

- Voltage Optimization: PSO's AMI meters capture 15-minute average voltage data. Coupling this data with analytics identifies trends where voltage has increased/decreased over time, which may be indicative of a transformer on the verge of failing or other service quality issues. In 2016, 534 locations impacting 2,288 customers were identified that had possible power quality issues indicating either high or low voltage conditions. The following issues were proactively identified, and the equipment was repaired or replaced prior to the equipment failing and avoiding a potential outage:

Voltage Optimization Metrics	Count
Transformer changed	129
Incorrect meter installed	48
*PSO voltage regulation equipment	296
Service Repair	61

*Regulators, capacitor banks, transformer LTC

Mr. Baker further testified that a fundamental component of any storm restoration plan is accurately determining the number of customers interrupted and their relative location on the electrical grid. To determine the location and number of customers interrupted, PSO has traditionally relied upon high-level system indications from our Supervisory Control and Data

Acquisition (SCADA) equipment. Our SCADA locations help us determine in most situations if a transmission line has faulted and, to a lesser degree, if a substation or distribution feeder is out of service. Information at this level is critically important to the operation of the electric grid overall, but does not provide detailed information at the individual customer level.

Prior to the recent installation of PSO's AMI meters, we were not aware, with any precision, of the level of individual customer outages. Our only indication of a customer outage in instances that did not trigger a high level SCADA notification occurred when customers telephoned to report an outage to our call centers. During a storm restoration event, a lack of specific and more precise outage information at the individual customer level creates a variety of operational challenges. Without accurate lower-level system information in the field, more personnel resources are required to physically "sweep" an area in a yard-to-yard manner to locate isolated customer outages versus having the intelligence to pinpoint a customer outage. The end result of less customer-specific outage information is longer restoration periods, increased operating expense and limited information to communicate with customers.

According to Mr. Baker, now that PSO's new AMI meters are in place, we know down to the individual meter location if a customer's electric service is interrupted without relying upon customers to call and report an outage. Similarly, we can use the AMI meter "polling" process to electronically verify electric service to customers has been restored and proactively search for isolated outages in an area thought to be restored without using the cumbersome yard-to-yard sweep process. In the case of the July 14, 2016 wind storm that impacted PSO's Tulsa service territory, we were able to poll hundreds of thousands of meters overnight on the second full day of the recovery effort to verify electric service was restored without sending field resources to individual customer locations. The information provided by the AMI polling process allowed us to make specific restoration resource work assignments prior to the start of work the next morning and avoid the time-consuming and costly yard-to-yard sweep process described earlier. The AMI-enabled process allowed us to wrap up the recovery efforts and restore electric service to the remaining customers approximately 24 hours earlier than would have been possible without the benefit of the AMI polling process. PSO was also able to release the majority of the off-system resources roughly 24 hours earlier versus what our pre-AMI restoration processes would allow.

According to Mr. Baker, in previous base rate cases, the assertion has been made that PSO's removal costs for certain distribution facilities, such as poles, are high as compared to the removal costs of other AEP operating companies.

Mr. Baker has responsibility over both the construction of distribution facilities, as well as the removal of distribution facilities for PSO. Removal costs are the costs associated with removing distribution assets from service. This includes costs such as labor and equipment.

Mr. Baker testified that PSO's removal costs are impacted by a number of factors, including PSO's aggressive system maintenance and replacement program (including the worst performing circuit program). As a part of this program, PSO replaces deteriorated facilities in difficult locations and applications, such as inaccessible easements and multi-circuit structures. Because of the challenging nature of these projects, they naturally have a higher removal cost, which can impact one of the individual cost of removal categories, like distribution poles.

However, when viewed in the broader context of PSO's total distribution removal costs, PSO's removal costs continue to appear reasonable when compared, for example, to other AEP companies.

PSO removed approximately 74 percent more poles per mile and approximately 117 percent more cross-arms per mile than the AEP system average for the period of 2016. These increased volumes occurred due to PSO's aggressive maintenance and replacement program. This activity is a core component of PSO's reliability performance as discussed in Section VI of my testimony. Also, as I discussed in Section VI of my direct testimony, PSO's electric system SAIDI reliability performance is 46 percent better when compared to other Oklahoma regulated utilities for the period of 2012-2016. Similarly, PSO's SAIDI reliability performance is 17 percent better as compared to regional investor-owned utilities, and 12 percent better when compared to similarly-sized national investor-owned utilities. This aggressive maintenance and replacement program, while providing reliability benefits, does tend to increase PSO's removal cost. Nevertheless, PSO's removal costs are necessary and reasonable and are managed cost effectively.

DONALD R. DOHRMANN

Dr. Donald R. Dohrmann, Principal and Director of Economics at ADM Associates, Inc. ("ADM"), testified on behalf of PSO.

Dr. Dohrmann testified that ADM was established in 1979 and has performed extensive work related to evaluating energy and demand programs and measuring associated savings. Specific to this Cause, ADM was retained to perform evaluation and savings measurements of PSO's PowerHours® programs.

According to Dr. Dohrmann, PSO has embarked on a campaign to cultivate a significant Demand Response (DR) resource. PSO used 2016 as a design and development or "experimentation" year which has resulted in a verified peak demand reduction of 5.81 MW through Direct Load Control events and the higher-cost time of day. In addition to demand reduction, the program achieved energy savings. The energy savings and demand reductions resulted in financial savings for program participants. On average, each participant saved $26 during PSO's on-peak months of May through October. Additionally, customers that participated in direct load control (DLC) events, on average, received approximately $12 in bill credits during the summer of 2016.

Dr. Dohrmann further testified that ADM's made recommendations to PSO for the PowerHours® program, and they can be characterized in two groups. The first set of recommendations concern the customer enrollment and device registration process, while the second set of recommendations are suggestions that might be characterized as continuous improvement efforts for the program.

Dr. Dohrmann testified that based on ADM's evaluation, he believed PSO has identified a viable, scalable, technical solution. They utilized 2016 as a "design and development" or "experimentation" year, and have taken steps to refine their program design based on data from the 2016 evaluation.

Dr. Dohrmann further testified that it appears that the 2016 PowerHours® program achieved similar technical performance as a mature DR program of similar design. As such, optimization of air conditioner cycling strategies or a reduction of non-responding device rates may yield a relatively small amount of improvement. Increased thermostat registration rates, however, can yield significant improvements to the program. Based on PSO's strategic marketing plan, this improvement could potentially be realized with relatively little cost, given that they may not require further infrastructural expenditures. Initial evaluation results from 2016 indicate that PSO's 2013 demand reduction projections seem reasonable and achievable, and have developed a pathway toward achieving those goals.

DEREK S. LEWELLEN

Mr. Derek S. Lewellen, Meter Infrastructure & Program Development Manager for Public Service Company of Oklahoma (PSO or Company), testified on behalf of PSO.

Mr. Lewellen testified that Advanced Meter Infrastructure ("AMI") System refers to systems that measure, collect, and analyze energy usage from meters through a communications network. This infrastructure includes hardware, such as meters, that enable two-way communications, and a communications network that provides the communication path between the meters and PSO's Information Technology (IT) systems. PSO's IT systems include the customer information systems, meter data management system, analytics hub, and the customer webportal. These IT systems utilize the AMI data to provide useful information to customers.

According to Mr. Lewellen, in 2013, PSO developed an initial project plan to install AMI meters, network equipment, and supporting IT systems. The plan and projected costs were based upon the experience gained with PSO's pilots, lessons learned from other utilities like AEP Texas and Oklahoma Gas and Electric (OG&E), PSO's procurement experience, and available pricing.

In early 2014, PSO refined the project plan to incorporate details such as the bidding processes for material and various contract resources, material delivery schedules, supporting IT projects, network design, meter and network installation schedules, customer communication plans, and consumer program development. All of these steps were layered into the project plan to ensure timely completion of the three-year project.

Mr. Lewellen testified that PSO competitively bid all aspects of the project to ensure requirements were met at the best available pricing. For example, PSO sought bids from multiple AMI communication providers for components such as network equipment and associated IT systems, meter vendors, meter installation contractors, network equipment installation contractors, and customer webportal providers.

Mr. Lewellen further testified that prior to and during AMI meter installation, PSO provided customers information about AMI, the customer webportal and associated Consumer Programs. This communication took place through multiple communications channels. For communications related specifically to the meter exchange, the following direct customer contact channels were used:

- Customer Letter: This was the initial contact in the form of a letter informing customers of their projected meter installation date. The letter was sent out approximately four to eight weeks prior to the new meter installation. Approximately 533,000 letters were sent to homes or businesses.

- Phone Blast Message: As a reminder of impending installations, customers were notified via phone message one to four weeks prior to the new meter installation.

- Door Hanger: At the time meters were exchanged, door hangers were left to inform customers that their existing meters had been exchanged for an AMI meter and how to contact PSO if they had any questions or concerns. The door hanger also included information about the meter, including benefits of AMI and how to access the customer webportal.

According to Mr. Lewellen, aside from minor cleanup, PSO completed deployment ahead of schedule in July 2016. In addition to deploying ahead of schedule, more meters were installed than originally projected, additional functionality such as an enhanced webportal was made available, and the project came in under budget.

The final project costs are $110,811,458 in capital expenditures, and $13,757,961 of O&M expenses for the AMI deployment period of 2014 through 2016. These totals are approximately $8.9 million and $6.7 million under the original cost estimates respectively.

Figure 2

AMI Program [illegible]	2014-2016 Projected	2014-2016 Actual	Amount Under Budget
Capital Spend – project	($119.7 million)	($110.8 million)	$8.9 million
O&M Spend - project	($20.5 million)	($13.8 million)	$6.7 million

Mr. Lewellen testified that PSO was able to leverage its purchasing power to obtain a lower cost for AMI meters and network equipment. This was the largest contributor to the decrease in capital costs because the projected capital cost per customer dropped significantly from the pre-deployment projection of $230 to $208 actual.

In terms of the reduced O&M costs, employee severance costs were approximately $2.0 million less than projected, staffing and salaries for new positions were $2.5 million less than the projected expense, and costs associated with the network and IT components were approximately $2.0 million less than originally projected. The staffing for new positions associated with AMI was also less than projected, which is an ongoing savings greater than originally projected according to Mr. Lewellen.

Mr. Lewellen testified that in Cause No. PUD 201300217, PSO projected a $5.0 million savings during the three-year deployment period and an additional $6 million in the first full year after deployment. In 2014 through 2016, PSO realized over $8.85 million in associated labor, overhead and vehicle savings, which is $3.35 million greater than the projected $5 million. PSO is also on target to achieve over $6 million in annualized labor, overhead and vehicle savings in 2017.

This savings represents the elimination of all 59 meter reader positions, the reduction of the field meter services staff from 52 employees to 28, and the elimination of two clerical positions. This is a total of 85 positions, as well as the associated vehicles, which equals the number of employee and vehicle reductions projected in Cause No. PUD 201300217. Current headcount and payroll are not expected to reduce further beyond the test year end.

Associated with the staffing and vehicle reductions, PSO avoided over 525,000 truck rolls and 1.3 million miles during 2016. This is approximately 60 percent less than the amount of miles driven prior to the deployment of AMI. PSO anticipates further mileage reductions in 2017 and is projected to meet or exceed the original projection of reducing miles driven by 75 percent or approximately 1.5 million miles.

Mr. Lewellen testified that the $11 million of guaranteed savings will be passed through to customers by the end of 2017.

According to Mr. Lewellen, with the ability to automate the disconnect and reconnect process of customer delinquent accounts, PSO is able to reduce the annual amount of charge-offs. Prior to the deployment of AMI, the three-year average for charge-offs was almost $6 million annually. In 2016, even though AMI was not yet fully deployed, the charge-off amount was slightly over $5 million, which represents an approximately $1 million reduction in bad debt. This reduction benefits all customers because it reduces the amount of uncollected billings that is passed through to all customers.

The charge-off reduction was accomplished through a combination of factors, mainly the ability to process almost 100 percent of the credit disconnects, and the ability to process credit disconnects after a moratorium. Prior to AMI, this was a manual process constrained due to the number of available resources, which allowed some customers to increase the delinquency period another 30 days. Also, having the ability to remotely connect/disconnect at the meter has eliminated the reconnect fee and reduced the number of services disconnected at the pole due to an inaccessible meter.

Mr. Lewellen further testified that now that AMI is fully deployed and PSO is offering Power PaySM (prepaid billing), PSO is expecting charge-offs to be further reduced in 2017, beyond the $1.6 million achieved over the deployment period (this is slightly less than the original projection of $1.7 million reduction during the same period). This expectation is based upon the experiences of other electric utilities with prepay programs that have created a positive impact on charge-offs. This is attributed to Power PaySM customers being able to defer up to $500 of past-due amounts coupled with the ability to pay the deferred amount over time.

AMI enables a reduction in both theft and consumption on inactive meters through the use of analytics and the installation of a remote disconnect switch in meters. Identifying and stopping theft faster has a positive impact on reducing the unknown amount of stolen or unaccounted-for energy. Prior to AMI (2012 through 2014), PSO investigated on average over

3,900 cases of theft annually. In 2016, AMI enabled PSO to investigate over 6,100 cases, which is a 60 percent increase in theft investigations.

For usage on inactive accounts, during the same three-year period prior to AMI, PSO identified over 4,600 inactive accounts that showed usage. Prior to AMI, these were found by field personnel during monthly meter reading in instances where the meter had been energized. Since the completion of AMI, this has declined to approximately ten inactive accounts having usage per month. At the most conservative end, using only the cases of theft that PSO identified in 2015 and 2016, PSO realized approximately $565,000 of savings in theft and usage on inactive meters.

Mr. Lewellen testified that obsolete meter avoidance creates a one-time avoided investment by replacing meters during the deployment period at the end of their useful lives and scheduled to be replaced due to manufacturer bulletins, testing, and field observations. PSO conservatively projected $1.2 million in avoided investment during the deployment period; however, the actual avoided investment was approximately $9.1 million. On average, PSO replaced over 16,000 meters annually due to obsolescence prior to the AMI deployment. This equates to over 48,000 meters during the three-year deployment. By replacing these meters with an AMI meter, the replacement costs associated with these meters are avoided.

According to Mr. Lewellen, AMI provides billing and call center efficiencies by reducing call volume and enabling employees to address inquiries in a more expeditious manner. Calls associated with billing, credit and investigation orders, which are approximately 40 percent of the annual call volume, have been reduced approximately 14 percent in 2016 alone. In comparing the annual call volume prior to AMI deployment (2012 through 2014) to the deployment timeframe (2015 and 2016), PSO received over 190,000 fewer phone calls. Based on an estimated cost per transaction, this reduction in phone calls represents a productivity savings of approximately $395,000 versus the original projection of $91,000. This amount will likely increase now that AMI is fully deployed.

Mr. Lewellen concluded by stating that PSO completed the installation of approximately 533,000 AMI meters ahead of schedule and under budget by over seven percent in capital expenditures and 33 percent in O&M expenditures. Further, despite being fully deployed for less than one year, operational, reliability, and customer experience benefits are already being realized at significant levels, many beyond original projections.

JOHN O. AARON

Mr. John O. Aaron, Manager, Regulated Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation (AEPSC), testified on behalf of PSO.

Mr. Aaron testified that he prepared PSO's jurisdictional and class cost-of-service studies and the development of the jurisdictional and class allocations and related Application Package (AP) schedules as required by OAC 165:70-5-4 and the Supplemental Package (SP) workpapers as required by OAC 165:70-5-20. While the Company's resources are predominantly used to provide service to Oklahoma retail customers (in excess of 99% of PSO's rate base is assigned to the Oklahoma retail jurisdiction as shown in Schedule K), OAC 165:70-5-4 requires the jurisdictional separation of the Company's rate base, revenues, expenses, and other applicable items. Mr. Aaron also supports the pro forma adjustments made to the test year customer, revenue, and sales volume data.

According to Mr. Aaron, a cost-of-service study allocates or assigns cost responsibility. PSO provides electric service at retail in Oklahoma subject to the jurisdiction of the OCC and to wholesale customers subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). Since PSO incurs costs to provide service to customers in two jurisdictions, a jurisdictional cost-of-service study is necessary to allocate or assign these costs, as measured by the total Company revenue requirement, to the appropriate jurisdiction to determine the cost-of-service for that specific jurisdiction. This is achieved in the jurisdictional cost-of-service study. Once the jurisdictional costs are determined, a class (e.g., residential, commercial, industrial, municipal and outdoor lighting) cost-of-service allocates or assigns the jurisdictional cost-of-service to the different classes based on the customers' use of PSO's electric system. The result is a fully-allocated embedded cost-of-service study that establishes the cost responsibility for each jurisdiction. An embedded class cost-of-service study assigns the retail jurisdictionally-allocated total Company costs to the individual retail customer classes to evaluate the cost PSO incurs in providing electric service to each individual retail customer class.

Mr. Aaron testified that a cost-of-service study relies on the utility company's historical test year accounting records to establish cost levels for rate base and expenses. Selected AP schedules and SP workpapers are the source of the cost levels for rate base and expenses in this cost-of-service study. The costs recorded in each FERC account are typically adjusted to reflect the applicable regulatory commission's policies and for known and measurable changes to the test year level of expenditures. Operating statistics such as peak demands, energy sales, customer counts and other data support the allocation of the costs to jurisdictions and classes.

A three-step process is followed to assign costs to the customer classes: functionalization, classification, and allocation.

According to Mr. Aaron, in the first step, the costs are separated by function (e.g., production, transmission, distribution, and customer services).

The second step in preparing a cost-of-service study is to separate the functionalized costs based on the characteristics of the electric service provided. The major cost classifications are demand-related costs, energy-related costs, and customer-related costs.

According to Mr. Aaron, the final step of the three-step process in preparing a cost-of-service study is to allocate the functional classified costs both to jurisdictions and classes of customers. The nature of the service provided and the load characteristics for each cost item such as peak demand (kW), energy consumed (kWh), or number of customers, serves as the basis for this allocation process.

The allocation process involves dividing the functionalized and classified costs among the jurisdictions and customer classes. The objective of this process is to assign costs in a reasonable and understandable way. Some costs are directly assignable to a single jurisdiction, a single class or even a single customer. For example, the cost associated with the poles and luminaires used for street lighting are directly assigned to the street lighting class.

Most costs, however, are attributable to more than one type of customer. These joint costs must be allocated to customer classes by an allocation methodology that recognizes each class's contribution to the cost driver such as peak demand, energy consumed, or the number of customers. This allocation ultimately determines the overall level of cost for the utility service provided.

Regarding transmission costs, Mr. Aaron testified that the Commission ordered the use of a 4-CP allocation based on testimony from other parties that stated PSO is a summer peaking utility, and therefore, it is appropriate to reflect the cost to use the transmission system during the four peak months (June through September) rather than all twelve months.

Mr. Aaron did not agree with use of a 4-CP allocation because the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) invoices transmission service customers, such as PSO, based on a 12-CP allocation. Therefore, the 12-CP transmission allocation methodology is the most appropriate allocation methodology for PSO's retail classes. Moreover, with the FERC-approved SPP RTO responsible for the planning and construction of the regional transmission system, the individual utility systems' (PSO in this case) load characteristics are no longer the primary driver in how transmission costs are determined. Historically, PSO planned and built its transmission system to serve its own retail and wholesale native load. That is no longer the case. According to Mr. Aaron, SPP now has functional control of PSO's transmission assets to meet regional and local needs; therefore, what has been done historically in regards to transmission planning and constructing as a basis for determining the appropriate transmission allocation, no longer exists.

Mr. Aaron testified that the 12-CP allocation of transmission costs reflects how PSO's customers use the transmission system as well as the method in which the charges by SPP are assessed. The customers that benefit from the use of the transmission system also bear their appropriate cost responsibility for their use of the transmission system. The 12-CP transmission allocation is the cost causation principle based on the activity that drives the costs.

Mr. Aaron stated that the 12-CP transmission allocation reflects the customers' actual use of the transmission system and the costs incurred by PSO in providing that service. Following the principle of cost causation, PSO's larger customers and users of the SPP transmission system should bear a larger and more equitable share of the costs billed by SPP.

Mr. Aaron testified that the cost-of-service studies were developed in a manner consistent with the studies preciously filed by PSO with the OCC.

Mr. Aaron further testified that the jurisdictional cost-of-service study is used to allocate costs between the retail and wholesale (FERC jurisdictional) customers. The jurisdictional allocations of rate base, revenues, and expenses shown in AP Schedules K-1 through K-3 are used in various accounting schedules to determine the costs and revenues that are applicable to the retail jurisdiction. The costs and revenues applicable to PSO's retail jurisdiction are then used in the retail customer class cost-of-service study as provided in SP WP L.

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

According to Mr. Aaron, all of the adjustments discussed by PSO witness Randall W. Hamlett and in his testimony are reflected in the jurisdictional and class cost-of-service studies submitted in this proceeding.

STEVEN L. FATE

Mr. Steven L. Fate, Vice President, Regulatory and Finance for Public Service Company of Oklahoma (PSO or Company), an operating company subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of PSO.

Mr. Fate testified that PSO provides high-quality electric service at reasonable prices to its customers. PSO's 547,000 customers represent a population of approximately 1.9 million Oklahomans spread over 232 cities and 30,000 square miles. PSO has 1,574 Oklahoma-based employees, maintains 20,100 miles of distribution lines, 3,200 miles of transmission lines, and 3,788 megawatts of power generation. PSO continually strives to deliver ever-higher quality of service at reasonable rates. In April 2017, PSO received a J.D. Power & Associates residential customer satisfaction score of 725 and is in the second quartile of our peer companies and ranked 51 out of 138 national brands. While we are pleased with this achievement, we understand our customers' expectations are also increasing and we are continuing to work hard to consistently meet and exceed customer expectations.

The deployment of AMI across our service territory has opened a new frontier in our ability to serve customers, allowing us to restore power more quickly, improve system reliability, offer more pricing options to choose from, and provide more information so customers can better manage their energy usage and control costs.

System reliability is a key component of customer satisfaction and we continue to focus on delivering power at a consistently high level with infrequent outages of short duration. PSO's system reliability compares very favorably to state, regional and national averages. A key reliability metric, the System Average Interruption Duration Index (SAIDI), is 46 percent better than average when compared to other Oklahoma regulated utilities for the period of 2012-2016. PSO's proven record of rapid service restoration from storms is being further enhanced by individual customer outage information now available in real-time through AMI.

Nineteen percent of the J.D. Power & Associates survey composite result is related to price. PSO is currently near the first quartile in satisfaction with price. These ratings are evidence of PSO's ability to deliver increasing customer satisfaction while maintaining reasonable rates. Between 2007 through 2016, PSO's residential price increased at a 0.8% annual growth rate as compared to U.S. electricity growth rate of 2.1%.

Mr. Fate testified that the use of the historical test year, along with the disallowance of some prudently-incurred costs and known and measureable adjustments, contributed to the regulatory lag experienced by the Company and has not provided PSO a reasonable opportunity to earn its authorized return on common equity. The disallowance of reasonably-incurred costs does not promote economic efficiency or result in fair, just, and reasonable rates. Ultimately, PSO's inability to approach its authorized return on equity (ROE) will hamper the Company's ability to attract the capital necessary to invest in our system and continue to effectively and reliably serve our customers.

	Table 1 Return on Common Equity	
	Earned	Authorized
2016	8.52%	9.50%
2015	8.62%	9.85%
2014	8.86%	10.15%

According to Mr. Fate, approval of appropriate depreciation rates is necessary to maintain adequate cash flow and is an essential component of fair rate relief. Preparing for the increasing rate of change in the industry necessitates that the Commission also focus on setting reasonable depreciation rates. The current depreciation rates do not recover the cost of the investment over a reasonable asset life.

Mr. Fate testified that the primary reason PSO was filing a base rate application at this time was the increase in expenses since its last rate case that is necessary for PSO to continue providing quality service to its customers. In addition to increasing transmission and distribution expense, since the last rate case PSO has approximately $625 million of additional investment not currently reflected in rates. Due to these increases, as well as adjustments adopted by this Commission to PSO's cost of service in Final Order Nos. 657877 and 658529 issued in Cause No. PUD 201500208, PSO's 2016 earned ROE was 8.52%, almost a full 100 basis points below its authorized return on common equity of 9.5% granted in November 2016.

Further, the two major cost recovery issues addressed in PSO's application are the inclusion in base rates of the remaining portions of PSO's full cost of the ECP and the AMI, which collectively represent a $335 million investment. Both of these investments are important steps in PSO's long-term strategic change intended to prepare the Company and customers for changes in the electric utility industry.

Mr. Fate further testified that PSO is requesting a base rate increase of approximately $170 million. This increase is due primarily to a revenue deficiency based on a test year ending December 31, 2016, adjusted for known and measurable changes to test year levels. Also as part of the increase, pursuant to Order No. 657877 issued in Cause No. PUD 201500208, PSO's request includes the consolidation into base rates the investment and expenses, net of savings, currently recovered through the AMI rider.

The total rate impact, which also includes the elimination of the remaining Distribution System Reliability Capital Carrying Costs recovered through the System Reliability Rider (SRR), results in an increase to PSO customers' rates of 11.5%.

According to Mr. Fate, the primary changes are as follows (dollars in millions):

Category	Cost
Depreciation	$58
Operation and maintenance	50
Income taxes	25
Other taxes	5
Return and other	42
Less Additional Revenues	(11)
Less Elimination of AMI Rider	(9)
Less Elimination of SRR	(3)
Change in Total Revenue	$156

Mr. Fate testified that depreciation has increased both due to higher levels of depreciable plant, as PSO has made additional investment in electric assets to serve customers, and the proposed increase in depreciation rates.

Operation and maintenance expenses have increased largely from higher Southwest Power Pool (SPP) transmission service and the distribution function. Much of the increase in the distribution function is related to storm expense.

Income taxes have grown because of the tax effect of the return on a growing rate base. Property taxes have increased due to a higher taxable base. Return and other increases are predominantly from the higher costs of financing the increased investments in electric utility assets.

Revenues have increased since the last test year used to set rates, which reduces the overall revenue requirement. The increased revenues are mostly from SPP transmission service revenues, miscellaneous revenue and slightly higher numbers of customers resulting in increased total kilowatt-hour sales.

Mr. Fate also testified that PSO is requesting OCC approval for: (1) recovery of and return on the cost of the environmental controls at Northeastern Unit 3 and Comanche Power Station (including deferred costs) and (2) recovery through depreciation rates and return on the remaining undepreciated book value of Northeastern Unit 4 by 2040. Environmental controls for Northeastern Unit 3 and Comanche went into service during the test year on February 26, 2016, and June 29, 2016, respectively. Northeastern Unit 4 was removed from service in April 2016.

According to Mr. Fate, the total cost for Northeastern Unit 3 controls, including AFUDC, was $180 million. The total cost for Comanche, including AFUDC, was $43 million. In sum, these investments were prudently managed, below their estimated cost, were reasonably incurred, and are currently serving customers.

Mr. Fate stated that if the Commission does not allow PSO to recover the cost of and receive a full return on Northeastern Unit 4 there would be significant negative financial implications for the Company. Beyond the negative financial implication for the Company, disallowing recovery of the shareholders' investment in an asset that served customers for 46 years, well beyond the original retirement date, it would send a perverse signal to the Company that its investment decisions should not be based on what it believes are in the best interest of customers, but alternatively decisions should focus on keeping assets in operation as long as possible – regardless of the cost and risk to customers. Stated differently, such an outcome will signal to management that if PSO had invested $750 million in environmental controls to keep Unit 4 in service, in spite of the strong evidence that to do so might not be in the long-term interest of customers, PSO could have avoided a negative financial outcome and increased its earnings rate base. This perverse incentive could have a negative effect on the making of good investment decisions in Oklahoma, and would be counter to the long-term interests of customers.

Mr. Fate testified that the Commission authorized PSO to recover various AMI-related costs net of guaranteed savings through the AMI rider. The Commission found among other things that:

1. The approximately $16 million of AMI investment as of January 31, 2014, was used and useful and should be recovered in base rates;

2. A regulatory asset should be created for the unrecovered net book value of non-AMI meters replaced by AMI meters to be amortized using a 9.58% depreciation rate;

3. PSO is required to guarantee $11 million in savings associated with labor, vehicles, and overheads over the first four years of AMI implementation; and

4. Creation of the AMI tariff to recover the investment cost of AMI using over/under accounting and recording as a regulatory asset, or regulatory liability, the difference between actual AMI revenue requirement and actual revenues collected under the tariff.

According to Mr. Fate, the Order stated that additional levels of AMI investment may be found used and useful by the Commission in future regulatory proceedings and that PSO must demonstrate that the purported benefits either have or will be delivered to customers. The Order also stated that the AMI tariff would remain in effect until the first base rate case subsequent to the full implementation of AMI. In 2016, PSO fully completed the AMI deployment and is now requesting the Commission make a finding that the additional AMI investment is used and useful and recoverable through base rates.

TOMMY J. SLATER

Tommy J. Slater, Vice President-Generating Assets for Public Service Company of Oklahoma, testified on behalf of PSO.

Mr. Slater testified that capital and O&M expenditures for PSO's fossil fuel generation were prudent, reasonable and necessary to maintain a safe, reliable, and environmentally-compliant generation fleet. O&M expenditures for the coal and gas-fired plants have decreased to a three-year average level of $81.0 million. With the retirement of Northeastern Unit 4, this represents a reasonable and sufficient ongoing level of O&M for the fleet.

According to Mr. Slater, capital projects and expenditures were undertaken to address environmental requirements, performance, reliability, or safety priorities at the generating plants. Since PSO's last base rate case, environmental controls at Northeastern Unit 3 and Comanche Power Station were completed and placed in service for $224.6 million - a combined $9.9 million under budget - and are operating as expected to help the plants meet environmental requirements.

Mr. Slater further testified that PSO owns and operates seven generation plants consisting of 18 units that are located within the state of Oklahoma. In addition, PSO owns approximately 15.6% of, and operates, the Oklaunion Power Station, located in Vernon, Texas.

Excluding other capacity entitlements that are used to meet the minimum Southwest Power Pool reserve margin requirement, PSO owns a net generating capacity of approximately 3,927 MW. Based on fuel type, PSO's generating units are approximately 15% (or 571 MW) coal-fired capacity and 85% (or 3,356 MW) natural gas-fired capacity.

Mr. Slater testified that environmental controls were installed at Northeastern Unit 3 to meet the requirements of the Mercury and Air Toxics Rule (MATS) and the Regional Haze Rule (RHR). The estimated project cost in 2015 of Northeastern Unit 3 environmental controls project was $190.6 million and the final completed cost as of the end of this test year was $181.2 million. The systems were placed in service on February 26, 2016, and the environmental emissions controls are operating reliably and performing as expected.

Mr. Slater testified that to achieve compliance with the Oklahoma Regional Haze State Implementation Plan for Nitrogen Oxide (NOx) emissions, low NOx burners were installed on Comanche 1G1 and 1G2 natural gas-fired combustion turbines. Other modifications were made at Comanche to improve the gas supply system , to upgrade turbine controls to support the additional requirements of the new equipment, and to make safety upgrades to the turbine building to meet Occupational Safety and Health Administration (OSHA) safety requirements.

The cost estimate for environmental controls at Comanche was $43.9 million and the completed cost was $43.4 million. The Low NOx burners and associated improvements were placed in service June 30, 2016 and have operated reliably.

Mr. Slater further testified that Northeastern Unit 4 was retired in place on April 15, 2016.

With respect to O&M expenditures, Mr. Slater testified that PSO's adjusted test year generation non-fuel O&M is approximately $80.2 million.

Mr. Slater further testified that three adjustments were made to test year generation O&M to adjust for known and measurable items. First, an adjustment was made to remove non-recurring O&M expenses resulting from the retirement of Northeastern Unit 4. Second, an adjustment was made to reflect the additional O&M required due to the environmental retrofits installed in 2016. Third, an adjustment was made to normalize the test year O&M amount with historic O&M levels (excluding Northeastern Unit 4). These three adjustments were added to the cost of service to accurately reflect the ongoing level of generation O&M expense for PSO.

Mr. Slater testified that PSO has added approximately $290.1 million to generation plant in service since Cause No. PUD 201500208. Of that total, $255.8 million is associated with major capital projects that had a cost greater than $500,000. In addition to the environmental controls, investments ranged from cooling tower replacement to upgrading turbine control systems. The breakdown of generation plant in service was summarized by Mr. Slater in Table 4 of his testimony.

With respect to retirement dates of the generating units, Mr. Slater testified that the expected useful life of a power plant depends on many factors, including the original design, the current condition of the unit, the operational demands on the unit and the potential cost in the future to replace the generation with another resource. An expected unit life does not represent a firm retirement date, but instead represents a best estimate of the expected operating life of such unit. It is assumed that at the end of the useful life of the unit, it will be economically beneficial to replace the unit with new generation rather than to continue to maintain it.

According to Mr. Slater, the expected useful life of a generating unit is determined with input from many groups. PSO operations staff and American Electric Power Service Corporation (AEPSC) Generation organization engineers routinely track any issues that arise during normal operation or that are found during equipment inspections.

With input from each of the groups, the condition of major equipment-planned capital investments, O&M expense levels, compliance with existing and expected environmental regulations, and replacement generation costs are all evaluated to create a reasonable assessment of the operating condition of each generating unit and determine the expected useful life. This allows PSO and AEPSC to best plan the future of the generating fleet, and ensure that a judicious approach is taken to provide a reliable supply of electricity for PSO's customers at reasonable prices.

Mr. Slater testified that AEPSC provides PSO generation with executive leadership, management direction, and staff support. Both PSO and AEPSC focus on the safe, reliable and low-cost operation of PSO's generation fleet for the benefit of its customers. This relationship is enhanced through the sharing of best practices and lessons learned.

While AEPSC provides planning, engineering and management support activities, PSO management is responsible for directing PSO generation employees in the day-to-day operation and maintenance of PSO's fleet of power plants, and serving as the interface between the plants and AEPSC. PSO employees at the plant level perform routine maintenance on PSO's power plants that may include predictive, preventive, and corrective maintenance.

Because AEPSC provides support to a large number of power plants, it is possible for PSO to have access to generation-related information and knowledge that is not readily available within the PSO organization. This synergy not only helps PSO operationally, but because the AEPSC charges are spread over a number of AEP operating companies, the cost to each AEP company is reduced. This means that it is not necessary for PSO to provide this level of support for its own organization on a stand-alone basis, which decreases the overall cost to PSO customers while maximizing the benefit of the knowledge accumulated from power plants across the country.

JENNIFER L. JACKSON

Jennifer L. Jackson. a Regulatory Consultant in Regulated Pricing and Analysis, part of the American Electric Power Service Corporation (AEPSC) Regulatory Services Department, testified on behalf of PSO.

Ms. Jackson testified that PSO is requesting a change in retail base rates of $169.5 million. The requested change includes approximately $146 million in new base rate increases and approximately $24 million from two riders transitioning to base rates. The riders and associated test year revenue requirements are the Advanced Metering Infrastructure Tariff (AMI), with a test year revenue requirement of approximately $21 million and the System Reliability Rider (SRR) with a test year revenue requirement of $3 million. According to Ms. Jackson, PSO has followed the revenue distribution recommendation from the Final Order in the most recent rate case, Cause No. PUD201500208, to assign the total revenue requirement change to the retail rate classes. EXHIBIT JLJ-1 details the revenue distribution by retail rate class. PSO's request results in a total retail change of approximately 11.43%. The total bill effect on the major rate classes as shown in EXHIBIT JLJ-1 is as follows:

- Residential Class 13.95%
- Commercial Class 9.66%
- Large Industrial Class 8.65%
- Lighting Class 15.76%

Ms. Jackson further testified that for an average residential customer using 1,100 kWh per month, the total bill change is approximately $14 per month.

Ms. Jackson stated that the current rate structures serve customers of all usage types including residential, small commercial, large commercial and small industrial, large industrial, municipal, and lighting. The PSO rate design is based on rate schedules that are differentiated by usage type, energy usage level, demand level, load factor, use of the system, and service voltage levels. Customers are grouped together by similar usage patterns and the costs to serve each class of customer are recovered through a mix of base service charges that recover a portion of the fixed costs of serving customers that generally do not vary with the demand or energy use of the customer, seasonal energy charges that vary with the monthly kWh usage of the customers, ratcheted demand charges based on a customer's maximum load required for service, and minimum bill components. Each of the components recovers costs associated with the generation, transmission, distribution, and customer service functions, and each rate schedule is designed to recover the costs of serving each customer class based on the type of customer and the mix of requirements needed to serve each class of customers.

According to Ms. Jackson, PSO was not proposing to make major changes to the rate structures of the retail rate schedules in this cause.

In this filing, PSO is proposing to continue the class definitions, structures, and basic principles of its rate design recently approved in Order Nos. 657877/658529 from Cause No. PUD201500208 and is not proposing any structural changes to its rate schedules.

Ms. Jackson testified that PSO was proposing new rate options. PSO is requesting approval of new rates for optional LED lighting service available for municipal service customers. PSO is also requesting approval of a methodology to adjust the amount of ad valorem taxes recovered from customers through their base rates. The currently-approved Tax Adjustment Rider has been modified to accommodate this request.

PSO is proposing to terminate the currently-approved SRR and the AMI Tariff through this filing. The SRR will no longer be used to recover additional distribution system reliability expenses or capital carrying costs (per the Order in PUD 201500208) and will expire when compliance rates are approved and in effect through a final order in the current proceeding. Similarly, the AMI tariff will remain in effect until compliance rates are approved and in effect based on the final order in the current proceeding. At that time the AMI Tariff will also expire. The revenue requirements associated with these terminated tariffs are proposed to be recovered through base rates in this filing.

Ms. Jackson further testified that PSO made minor revisions to the language in its Electric Service Rules, Regulations, and Conditions of Service to incorporate updated information related to PSO's digital metering including how to read the advanced digital meters. PSO has also proposed a new facilities rental service agreement for customers requesting equipment beyond standard service.

According to Ms. Jackson, the revenue distribution is the rate design mechanism by which the proposed change in revenue requirement is assigned to the customer classes. The revenue distribution also determines the revenue requirement targets for each rate class in order to design rates that achieve the required revenue.

PSO's revenue distribution proposal follows the revenue distribution recommendation from the Final Order in the most recent rate case, Cause No. PUD201500208, to assign the total revenue requirement change to the retail rate classes. The Order followed the Public Utility Division's recommendation to move all major rate classes to the cost-to-serve each major class without causing major bill impacts. PSO has proposed to move its major retail rate classes to its required cost-to-serve.

Ms. Jackson testified that Table 1 indicates the percentage change in base rates needed to bring each major rate class to an equalized return, the percentage change in base rates proposed by PSO, the proposed total bill change when current fuel and compliance rider revenues are included with the base rate change, and the relative rate of return (RROR) at proposed rates for each major rate class based on the proposed revenue distribution.

Table 1				
Class	Equalized Base Rate Percentage Change	Proposed Base Rate Percentage Change	Total Bill Percentage Change	RROR @ Proposed
Residential	31.01%	31.01%	13.95%	1.00
Commercial & Small Industrial	24.22%	24.16%	9.66%	1.00
Large Power & Light SL3	28.20%	28.17%	9.36%	1.00
Large Power & Light SL2	31.53%	31.53%	9.05%	1.00
Large Power & Light SL1	16.77%	16.64%	4.61%	1.00
Lighting	24.92%	24.86%	15.76%	1.00
Total Retail	28.36%	28.33%	11.43%	1.00

Ms. Jackson further testified that Table 2 shows the present class returns relative to the present retail return on rate base of 3.13 percent, present class returns relative to the proposed rate of return of 7.22 percent, and the proposed class returns relative to the total proposed retail return of 7.22 percent with greater individual class detail.

Table 2			
Class	Present Rates Relative ROR at 3.13%	Present Rates Relative ROR at 7.22%	Proposed Rates Relative ROR at 7.22%
Residential	.94	.39	1.00
LUGS	.96	.66	1.00
General Service	1.14	.44	.99
Power & Light	1.13	.48	1.05
Large Power & Light SL3	.98	.41	1.00
Large Power & Light SL2	.35	.36	1.00
Large Power & Light SL1	1.46	.60	1.00
Municipal Service	3.32	1.44	1.00
Municipal Pumping	1.18	.51	1.01
Lighting	1.52	.64	1.00
Total Retail	1.00	1.00	1.00

Regarding the Ad Valorem Tax Adjustment, Ms. Jackson testified that PSO is requesting that the Final Order in this case recognize the amount of ad valorem tax approved to be recovered through base rates in this case. PSO requests that the Tax Adjustment Rider be modified to include an ad valorem tax adjustment factor that will be adjusted annually to account for an incremental amount of property (ad valorem) taxes expensed above or below the baseline amount included in base rates. In other words, PSO is requesting to trueup the difference between the actual ad valorem taxes recorded on PSO books and records and the actual amount being recovered from customers, annually. The ad valorem tax adjustment will be allocated to customers in the same manner in which ad valorem taxes are currently recovered from customers through their base rates and recovered on a per kWh basis. According to Ms. Jackson, PSO has modified the currently approved Tax Adjustment Rider (TA) to accommodate this proposal. If approved, the factors will be set to zero until the first annual update.

WAYMAN L. SMITH

Mr. Wayman L. Smith, Director, West Transmission Planning for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of PSO.

According to Mr. Smith, PSO has invested approximately $53.1 million in its transmission system beyond the investment included in the last base rate proceeding. This investment was made to maintain system reliability by replacing failed, aging infrastructure and/or poorly performing equipment, restoring the system following major weather events, upgrading the system in order to meet increasing load requirements and to facilitate new customer connections. The investments for all of these transmission capital projects are necessary and reasonable to ensure PSO's transmission system meets customer demand while adhering to North American Electric Reliability Corporation (NERC), SPP and AEP reliability criterion.

PSO's adjusted test year transmission O&M expenses are approximately $90.7 million including both Non-RTO and RTO expenses. The Non-RTO transmission O&M expenses are necessary and reasonable, and primarily consist of planning, engineering, operating, and maintenance activities performed to support PSO's transmission system. The RTO transmission O&M expenses are necessary and reasonable and consist of those expenses that are allocated to PSO by the SPP RTO for benefits and services received from SPP.

Mr. Smith further testified that the PSO transmission system is managed by the AEP Transmission business unit (AEP Transmission), which utilizes PSO employees, AEPSC employees, and external contractors. AEPSC employees are a shared resource among AEP affiliate companies and allow AEP Transmission to achieve economies of scale, maintain low costs and provide operational efficiencies in managing the PSO transmission system. These AEPSC services to PSO were approximately $5.4 million during the test year. Each of the services provided to PSO by AEP Transmission is necessary for PSO to provide reliable electric service.

According to Mr. Smith, there are over 3,200 circuit miles of transmission lines in the PSO system, stretching from the western Oklahoma border with the Texas panhandle to the eastern Oklahoma border with Arkansas, covering the southern and eastern portion of the state. The voltage levels of the PSO transmission facilities (both overhead and underground) range from 69 kV to 345 kV, as shown in EXHIBIT WLS-1.

PSO has synchronous interconnections with the following transmission owners: SWEPCO, The Empire District Electric Company, Oklahoma Gas & Electric Company (OG&E), Grand River Dam Authority, KAMO Power, Western Farmers Electric Cooperative, Southwestern Power Administration, Associated Electric Cooperative, Inc., Southwestern Public Service Company, Westar Energy, Inc., ITC Great Plains, LLC, OK Transco, Oklahoma Municipal Power Authority and Coffeyville Municipal Light and Power. PSO is also connected asynchronously to the Electric Reliability Council of Texas (ERCOT) by a high-voltage direct current (HVDC) interconnection in north Texas near the Oklaunion generating facility.

Mr. Smith further testified that SPP has functional control of PSO's transmission facilities. PSO purchases regional Network Integration Transmission Service (NITS) under the SPP Open Access Transmission Tariff (SPP Tariff) to serve its retail customers. PSO's transmission system is also used to provide wholesale transmission service under the SPP Tariff to loads served by the other utilities, cooperatives, and municipalities connected to PSO's transmission system. PSO's transmission system also facilitates the delivery of energy under the SPP Integrated Market.

The PSO transmission system is planned, constructed, operated, and maintained through the coordinated efforts of AEP Transmission and SPP. AEP Transmission achieves economies of scale by enabling AEP affiliate companies to share common support staff and resources that help provide cost and operational efficiencies.

Because PSO is interconnected with other companies' transmission systems in Oklahoma and surrounding states, the AEP Transmission organization works closely with SPP and its neighboring utilities to plan and operate the transmission grid. SPP's transmission planning and operational requirements are set out in the SPP Tariff and the SPP Membership Agreement.

Table 1 lists the major transmission projects (over $500,000) that have been added to transmission plant in service since PSO's last rate case. These 11 projects total approximately $36.2 million. Additional projects, each less than $500,000 individually, total approximately $16.9 million to bring the total capital invested during this period to approximately $53.1 million.

Table 1: Transmission Projects Added to Plant in Service Since Last Rate Case

[illegible]	Project Description	General Project Category	Total Cost
1	System Improvement Program	Asset Improvement	$9,369,867
2	PSO Storm Recovery	System Restoration	$8,297,643
3	PSO Transmission Telecom Upgrades	Asset Improvement	$5,828,244
4	Asset Replacement and Refurbishment	Asset Improvement	$3,358,710
5	Oneta – Broken Arrow North 138 kV Reconductor	Reliability	$2,866,464
6	Grady Point of Delivery (POD)	Customer Service	$1,692,023
7	Major Equipment Spares	Asset Improvement	$1,109,556
8	Asset Health Monitors - Riverside	Asset Improvement	$1,051,384
9	PSO Vegetation Management Program	Forestry	$1,046,273
10	Lawton Eastside – Lawton 112th & Gore 138 kV Relocation	Customer Service	$908,869
11	Rebuild Carson Substation – Add 4th Transformer	Distribution Driven	$636,857
12	Subtotal of Projects less than $500,000		$16,943,418
	Total		**$53,109,308**

The transmission projects in Table 1 represent: (1) replacement and rehabilitation projects; (2) upgrades required to serve increased customer load, including NERC and SPP reliability compliance requirement projects; (3) customer connections; (4) distribution-driven projects; and (5) storm recovery.

Regarding O&M expenses, Table 2 provides a description of the FERC accounts and the corresponding adjusted test year expenses. Mr. Smith testified that the adjusted test year transmission O&M expenses are approximately $90.7 million. This total includes transmission O&M expenses for both Non-RTO and RTO accounts.

Table 2 – Adjusted Test Year Expenses by FERC Account

FERC Account	Account Description	O&M Expenses	[illegible]	Adjusted O&M
560	Oper Supervision & Engineering	$3,752,798	($978,060)	$2,774,738
561*	Load Dispatch, Reliability, Plng & Stds Develop, Transmission Service Studies	$2,753,756	$5,746	$2,759,502
562	Station Expenses – Nonassoc	$456,387	($3,610)	$452,777
563	Overhead Line Expenses	$254,824	($5,245)	$249,580
566	Misc Transmission Expenses, SPP FERC Assessment Fees, R King Trans Cnter Exp – Affil	$3,717,283	($539,283)	$3,178,000
567	Rents – Nonassociated & Associated	$5,399	$0	$5,399
568	Maint Supv & Engineering	$155,935	($5,790)	$150,146
569	Maintenance of Structures, Computer Hardware & Software, & Communication Equip	$1,082,116	($417)	$1,081,699
570	Maint of Station Equipment	$2,407,756	$24,480	$2,432,236
571	Maintenance of Overhead Lines	$3,175,160	$1,433,862	$4,609,022
572	Maint of Underground Lines	$100	($96)	$4
573	Maint of Misc Transmission Plt	$231,481	($39,098)	$192,383
Non RTO Accounts	**Subtotal**	**$17,992,995**	**($107,510)**	**$17,885,485**
561**	Scheduling, System Control & Dispatching Svcs, Reliability, Plng & Stds Develop	$11,282,474	$1,392,551	$12,675,025
565	Trans of Electricity for Others	$85,563,032	($26,741,607)	$58,821,425
575	Regional Market Expenses	$1,229,619	$106,170	$1,335,789
RTO Accounts	**Subtotal**	**$98,075,125**	**($25,242,886)**	**$72,832,239**
	Total	**$116,068,120**	**($25,350,395)**	**$90,717,724**

*includes FERC Accounts 561.1, 561.2, 561.3, 561.5, 561.6
**includes FERC Accounts 561.4, 561.8

Mr. Smith further testified that SPP works with its members to determine and construct the transmission infrastructure needed in the near- and long-term planning horizon to maintain electric reliability, meet public policy mandates and provide economic benefits. SPP does not own or build transmission assets. The SPP Tariff and governing documents contain the rules that govern transmission construction by SPP Transmission Owning members. SPP's transmission planning services include the development of regional transmission expansion plans, oversight of transmission upgrade construction in accordance with approved plans, and development and implementation of cost allocation methodologies to ensure appropriate recovery by the constructing SPP Transmission Owners (TOs). SPP's construction oversight includes monitoring project status and costs through quarterly reporting by the constructing TOs and ensuring proper adherence to cost estimates and construction in-service need dates.

According to Mr. Smith, the SPP transmission expansion plan (STEP) is a compilation of SPP-directed projects based on studies performed by SPP to determine upgrades needed to maintain reliability, provide transmission service, provide for generation interconnections, and provide economic benefit to its Members into the future. SPP's transmission planning processes seek to identify system limitations and needs, develop cost-effective transmission solutions, and ensure timely completion of needed system expansion within reasonable cost expectations. Rather than looking at the needs of just one load serving entity (LSE), SPP assesses needs from a larger, regional perspective and determines necessary new transmission infrastructure that would provide the most net benefits to the region.

Mr. Smith further testified PSO, as an LSE taking regional network integration transmission service under the SPP Tariff, is responsible for its load share of the revenue requirement associated with infrastructure investment in the greater region of SPP's transmission system, and thus, the charges for which PSO is responsible are not fully controllable by the Company. However, those costs are reasonable to maintain and provide reliable transmission service in the greater region of the SPP transmission system.

Mr. Smith testified regarding the benefits to customers from building transmission facilities. Strengthening SPP's transmission infrastructure addresses SPP's transmission service customer needs to provide reliable transmission service to all customers. A strong transmission infrastructure helps to relieve the transmission constraints identified in SPP's generation interconnection queue to bring additional generation on line to provide additional energy sources. The SPP RTO planning processes under the SPP Tariff provide the means for LSE's (including PSO), generators that require interconnection and other parties needing transmission services to obtain these transmission services from the SPP.

Mr. Smith further testified that when storms devastate an electric system, such as ice storms or tornadoes, the transmission system must be robust enough to provide service to customers in other areas of the system. While the damage may be severe to specific portions of the transmission system, the transmission system is designed to be diverted around the damaged facilities to continue to reliably serve load in areas not geographically near the storm-damaged facilities. Natural disasters can cause major damage to the electrical grid but these types of outages confirm the need for investment in both transmission and distribution to reliably serve load. The combination of a robust transmission and distribution system provides a public benefit in increased reliability to customers.

As new transmission lines are put in service, more paths become available for energy to flow to loads. This benefits customers by enhancing reliability through new transmission paths, keeping their lights on in times of system stress.

According to Mr. Smith, there exists a public need for an improved robust electric transmission system that can deliver lower-cost energy to customers. Investment in needed transmission infrastructure to accommodate the flexibility in the transmission system to provide access to generation with lower cost-energy provides a public benefit.

ANDREW R. CARLIN

Mr. Andrew R. Carlin, Director of Compensation & Executive Benefits for American Electric Power Service Corporation (AEPSC), a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), testified on behalf of PSO.

Mr. Carlin testified that the employee compensation that PSO seeks to include in its cost of service for rate making purposes is reasonable, appropriate and beneficial to PSO customers. The inclusion of incentive compensation in a utility's cost of service for rate making purposes should be based on whether the total compensation provided to employees is reasonable and market-competitive unless such compensation is inefficient, improvident or imprudent.

Mr. Carlin compared PSO's compensation levels and practices to market compensation levels using third-party compensation surveys to determine a market-competitive range centered on the market median for similar positions as a check on reasonableness. According to Mr. Carlin, that comparison shows that PSO's average target total compensation for physical and craft positions is 6.4% percent below the market median. If PSO's annual incentive compensation were to be excluded, then total compensation for six of the 10 physical and craft positions (60.0 percent) would fall below the market-competitive range and PSO's average total compensation would fall to 10.8 percent below the market median, which is below the +/- 10 percent the competitive range for these positions. The comparison also shows that the PSO's target total compensation for non-executive exempt positions was below the market median but within a +/- 15 percent market-competitive range. According to Mr. Carlin, if the Company's annual incentive compensation were to be excluded, then total compensation for these positions would fall to 10.2 percent below the market median, which is within but at the low end of the market competitive range. However, 3 of 22 individual positions (13.6 percent) would fall below the market competitive range. Thus, the annual incentive compensation paid by PSO, or a similar amount of additional base pay, is necessary to maintain the competitiveness of PSO's compensation for these positions.

Mr. Carlin evaluated AEP's management and executive positions total direct compensation (TDC) to a third-party compensation study. The peer group used for this study consists of similarly-sized utility companies that represent the talent markets from which AEP must compete to attract and retain management and executive employees. An analysis of this study shows that target TDC for the 17 executive positions whose time and expense is generally allocated to PSO were within the +/- 15 percent market competitive range on average as of July 1, 2016. However, AEP's total compensation would be below the market-competitive range for 100 percent of these executive positions without either the annual incentive compensation or the long-term compensation portion of total compensation, unless it was replaced with additional base salary.

Mr. Carlin testified that the inclusion of a financial component in annual incentive compensation plans is prevalent throughout the utility industry. Other state commissions have approved the inclusion of annual and long-term incentive compensation in utility rates. The Commission has also approved inclusion of long-term incentive compensation because "the interests of the Company's shareholders and its customers were substantially aligned." Nearly all public utility companies of AEP's size and complexity have similar long-term incentive compensation, as do nearly all public general industry companies.

Mr. Carlin testified that the total value of compensation that the Company provides is within the market-competitive range required to attract and retain the suitably knowledgeable, experienced and qualified employees the Company needs to safely, efficiently and effectively provide reliable electric services to customers. The annual and long-term incentive compensation is designed to effectively control overall expenses, which reduces the cost of service to customers. The compensation paid to employees, including its variable annual and long-term incentive components, is a reasonable, necessary and prudent cost of providing service to customers according to Mr. Carlin.

Mr. Carlin testified that all of the Company's employees, except temporary positions, participate in annual incentive compensation. Accordingly, all employees, from Customer Service Representatives in the Customer Operations Center, to lineman, to generation plant personnel have an incentive compensation opportunity that links incentive compensation to performance measures. The majority of the annual incentive compensation goals for the PSO employees are measured at the operating company (PSO) level. The performance measures and communications are fully described in written documents for major business units and other groups within the organization.

For the test year there were separate performance measures for PSO (distribution and staff functions), Customer & Distribution Services, Generation, Transmission and other smaller groups. The PSO annual incentive compensation component used a balanced scorecard consisting of three categories of performance objectives: Infrastructure Development (25%), Customer Experience (40%) and Employee Experience (35%).

Mr. Carlin further testified that the various non-financial, operational measures (i.e., reliability, regulatory pursuit of customer-driven programs, customer satisfaction, economic development, efficiency and effectiveness, risk mitigation, customer experience, emergency restoration planning, employee culture and safety) benefit customers by promoting reliable, efficient and safe operations. The financial measures benefit customers by promoting the optimal use of the Company's limited financial resources, leading to operations and maintenance (O&M) and capital cost control, and contributing to the financial health of the Company, all of which benefits both customers and shareholders alike through the more reasonable O&M and capital expenditure levels that are achieved. Customers directly benefit from incentive measures designed to ensure fiscal discipline. Efficient use of the Company's limited resources results in more work being done for the same cost and, ultimately, a lower cost of service. Operational measures improve the Company's ability to meet customers' service expectations while financial measures help effectively control O&M and capital expenditures. These types of measures work together to better meet customers' cost and service expectations as well as shareholders' financial expectations.