

**BEFORE THE CORPORATION COMMISSION 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**

**FILED**  
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CORPORATION COMMISSION  
OF OKLAHOMA

**RESPONSIVE TESTIMONY  
OF  
MARK E. GARRETT**

**ON BEHALF  
OF  
OKLAHOMA INDUSTRIAL ENERGY CONSUMERS  
("OIEC")**

**Responding to the Direct Testimony of:**

**Andrew R. Carlin  
David J. Wathen  
Steven L. Fate  
Randall W. Hamlett  
Brian J. Frantz  
Tommy J. Slater  
C. Richard Ross  
Pauline M. Ahern**

**September 21, 2017**

**Prepared Responsive Testimony of Mark E. Garrett  
September 21, 2017  
Revenue Requirement Issues**

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**I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY**

1 **Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A: My name is Mark Garrett. My business address is 4028 Oakdale Farm Circle, Edmond  
3 Oklahoma 73013.

4  
5 **Q: WHAT IS YOUR PRESENT OCCUPATION?**

6 A: I am the President of Garrett Group, LLC, a firm specializing in public utility regulation,  
7 litigation and consulting services.

8  
9 **Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR  
10 PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION?**

11 A: I am an attorney and a certified public accountant. I work as a consultant in the area of  
12 public utility regulation. I received my bachelor's degree from the University of  
13 Oklahoma and completed post graduate hours at the University of Texas and Stephen F.  
14 Austin State University. I received my juris doctorate degree from Oklahoma City  
15 University Law School and was admitted to the Oklahoma Bar in 1997. I am a Certified  
16 Public Accountant licensed in the States of Texas and Oklahoma with a background in  
17 public accounting, private industry, and utility regulation. In public accounting, as a  
18 staff auditor for a firm in Dallas, I primarily audited financial institutions in the State of  
19 Texas. In private industry, as controller for a mid-sized (\$300 million) corporation in  
20 Dallas, I managed the Company's accounting function, including general ledger,  
21 accounts payable, financial reporting, audits, tax returns, budgets, projections, and

1 supervision of accounting personnel. In utility regulation, I served as an auditor in the  
2 Public Utility Division of the Oklahoma Corporation Commission from 1991 to 1995.  
3 In that position, I managed the audits of major gas and electric utility companies in  
4 Oklahoma. Since leaving the Commission, I have worked on numerous rate cases and  
5 other regulatory proceedings on behalf of various consumers and consumer groups. I  
6 have provided both written and live oral testimony before public utility commissions in  
7 the states of Alaska, Arizona, Arkansas, Colorado, Massachusetts, Nevada, Oklahoma,  
8 Texas and Utah. I have also provided written testimony in the state of Florida. My  
9 clients include large industrial customers, large gaming customers in Nevada, large  
10 hospitals and hospital groups, cities, universities, and large commercial customers. I  
11 have also testified on behalf of the commission staff in Utah and the offices of attorneys  
12 general in Oklahoma and Florida. I have served as a presenter at the NARUC  
13 subcommittee on Accounting and Finance, on the issue of incentive compensation, and  
14 as a regular instructor at the New Mexico State University's Center for Public Utilities  
15 course on basic utility regulation.

16  
17 **Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THIS COMMISSION?**

18 A: Yes, they have. A more complete description of my qualifications and a list of the  
19 proceedings in which I have been involved are included at the end of my testimony.  
20

21 **Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?**

22 A: I am appearing on behalf of Oklahoma Industrial Energy Consumers (OIEC).

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**Q: WHO IS OIEC?**

A: OIEC is an association, consisting of a diverse group of large consumers of energy in Oklahoma, which is involved in regulatory and legislative matters primarily involving natural gas and electric power.

**Q: WHAT IS OIEC'S INTEREST IN THIS PROCEEDING?**

A: OIEC is an association which represents the interests of industrials and other large energy consumers. Electric power costs can constitute a significant percentage of industrial operating costs. Electric power supplies are generally purchased from utilities pursuant to standard tariffs filed at the Commission. Industries served by PSO often operate in highly competitive business environments and, thus, OIEC is interested in the Commission determining rates for PSO that achieve reliable power supply at the lowest and most reasonable costs possible.

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A: The purpose of my testimony is to address various revenue requirement issues identified in PSO's rate case application and to provide the Commission with recommendations for the resolution of these issues. I also sponsor *Exhibit MG-2* included with this testimony, in which the overall impact of OIEC's recommendations is set forth. A summary of the OIEC impacts is shown below:

Rate Increase Proposed by PSO	\$ 169,667,526
OIEC Adjustments	\$ (117,336,487)

1	Riders rolled into Base Rates	\$ (24,000,000)
2	<b>Rate Increase after OIEC Adjustments</b>	<b><u>\$ 28,331,039</u></b>

3 PSO's proposed increase represents a 28.33% increase in non-fuel base rates.<sup>1</sup>

4

5 **Q: WHAT INCREASE IS THE COMPANY REQUESTING TO ITS REVENUE**

6 **REQUIREMENT?**

7 A: In its Application, the Company is seeking a \$169 million rate increase, which represents

8 a 28.33% increase in base rates. This one of the largest rate increases to my knowledge

9 ever sought by a utility in the state of Oklahoma.

10 **Q: WHEN DID THE COMMISSION LAST ESTABLISH NEW RATES FOR PSO?**

11 A: In December of last year, the Commission established new rates for PSO. This case has

12 been filed on the heels of the Company's last rate case, Cause PUD 201500208. In fact,

13 this case is being pancaked on top of the rate-effective period from the last rate. In other

14 words, this case was filed during the first year of new rates from the Company's last rate

15 case, Cause PUD 201500208. New rates went into effect in January 2017 and this case

16 was filed six months later in July.

17 **Q: WHAT IS THE COMPANY TRYING TO ACHIEVE IN THIS CASE?**

18 A: It appears that the Company is trying to relitigate many of the issues it lost in the last rate

19 case. These issues include depreciation expense, increased payroll costs, recovery of

20 incentive compensation and increases in other O&M expense levels. The Commission

21 set the appropriate level for these costs, which were implemented in January of this year,

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<sup>1</sup> See Jennifer L. Jackson's direct testimony at Table 1, page 10.

1 and the utility is seeking a change to such costs a short 6 months later. This is  
2 inappropriate. In reality, the purpose of this case was to (i) recover capital investments  
3 associated with the remaining costs of PSO's Environmental Compliance Plan ("ECP")  
4 for assets that were not completed and in service in the Company's last rate case and (ii)  
5 recover capital investments associated with the Company's implementation of automated  
6 meters (AMI). It was not meant to be an opportunity for the Company to re-litigate the  
7 last case.

## II. RATE BASE ADJUSTMENTS

### II. A. RATE BASE - 6 MONTH POST TEST YEAR ADJUSTMENT

8 **Q: ARE YOU PROPOSING ADJUSTMENTS TO THE COMPANY'S PRO FORMA**  
9 **RATE BASE?**

10 A: Yes. My adjustments update the Company's rate base accounts to their balances at June  
11 30, 2017. In Oklahoma, the Commission is required by law (Title 17 § 284) to give  
12 effect to known and measurable changes that occur within six months of test year end.  
13 In this application, the 6-month cut-off period for post test year adjustments is June 30,  
14 2017.

15  
16 **Q: HOW ARE THE ADJUSTMENTS CALCULATED TO REFLECT ACTUAL**  
17 **INVESTMENT LEVELS AT JUNE 30, 2017?**

18 A: The adjustment is calculated by comparing the Company's requested levels in plant,  
19 accumulated depreciation and all other rate base accounts at test year end, December 31,  
20 2016, to the actual balances in these accounts as of June 30, 2017. As a result of this

1 calculation, all of the Company's investment in plant that is actually in service within six  
 2 months of test year end is included in rate base along with all inventory levels and  
 3 regulatory asset balances. Also, all offsetting decreases in the investment levels, such as  
 4 accumulated depreciation, accumulated deferred income taxes, customer deposits and  
 5 regulatory liabilities are recognized as well.

6 **Q: HAS THE COMMISSION PREVIOUSLY ACCEPTED THIS APPROACH?**

7 A: Yes. To my knowledge, in virtually every litigated rate case since Cause No. PUD  
 8 200400610, ONG's 2005 rate case, which was the first rate case heard by the  
 9 Commission after passage of the 6-month rule in Title 17 § 284, the Commission has  
 10 used this approach.

11 **Q: PLEASE SUMMARIZE THE ADJUSTMENTS TO PRO FORMA RATE BASE**  
 12 **TO REFLECT ACTUAL NET INVESTMENT LEVELS AT JUNE 30, 2017.**

13 A: OIEC's adjustments to the Company's pro forma rate base are set forth below. The  
 14 detailed calculations reflecting PSO's actual investment levels at June 30, 2017 are set  
 15 forth in *Exhibit MG-2.1* attached to this testimony.

<b>Table 1: OIEC 6-Month Adjustments to Rate Base</b>				
	Description	PSO Adjusted Rate Base at 12/31/16	Actual Rate Base at 6/30/17	OIEC Adjustment Total Company
1	Plant in Service	\$ 4,983,250,552	\$ 5,052,446,777	\$ 69,196,225
2	Accumulated Depr.	(1,502,061,083)	(1,534,734,728)	(32,673,645)
3	Accumulated Deferred Taxes	(1,046,151,269)	(1,085,501,189)	(39,349,920)
4	Materials and Supplies	50,488,000	43,750,108	(6,737,892)

5	Customer Deposits	(49,674,708)	(50,661,422)	(986,714)
6	Regulatory Assets	127,004,496	119,744,369	(7,260,127)
7	Regulatory Liabilities	(33,427,564)	(33,342,708)	84,856

1 **Q: HAVE YOU RECOMMENDED ANY ADJUSTMENTS TO 6-MONTH UPDATES**  
2 **THAT MAY DIFFER SLIGHTLY FROM THAN THOSE PROPOSED BY THE**  
3 **COMPANY OR OTHER INTERVENERS?**

4 **A:** Some slight differences may occur. For example, PSO proposes a 13-month average for  
5 customer deposits. A 13-month average calculates the amount to include in rate base for  
6 any particular account by taking an **average** of the month end balances in that account  
7 over the prior 13-month period. Typically, this approach is used when an account  
8 balances tends to fluctuate up and down month to month. When an account, however, is  
9 trending in one direction or the other, the last balance in that account should be used for  
10 setting the investment level to include in rates. Therefore, I have updated the customer  
11 deposit account to reflect the actual account balance as of June 30, 2017.

**II. B. PREPAID PENSION ASSET**

12 **Q: WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE COMPANY'S**  
13 **PREPAID PENSION BALANCE?**

14 **A:** I am proposing to reduce PSO's prepaid pension balance by \$36,508,316, which  
15 represents the unexplained, and unsupported, starting balance back in 2003 in the  
16 Company's prepaid pension calculations. After 2003, the Company is able to show, in  
17 Exhibit RWH-6, a year by year history of changes in the account balance, showing both

1 increases in the balance from adding in contributions and decreases in the balance from  
2 netting out annual costs. Prior to 2003, however, the Company cannot account for what  
3 they claim is an existing starting balance. Without any support for this balance, it cannot  
4 be included in rates.

5 **Q: WHAT DOES THE PREPAID PENSION BALANCE REPRESENT?**

6 A: In general terms, a prepaid pension balance is the accumulated difference between (1)  
7 the Statement of Financial Accounting Standards No. 87 ("SFAS 87") calculated pension  
8 costs each year – the amount included in rates – and (2) the actual contributions made by  
9 the Company to the pension fund. When there is a debit balance, the Company has been  
10 contributing more to the fund than its SFAS 87 calculated cost levels. Or, in theory, the  
11 Company has been contributing more to the pension fund than it has been collecting in  
12 rates.

13  
14 **Q: ARE THESE CONTRIBUTIONS MANDATORY?**

15 A: No. PSO's contributions in excess of the SFAS 87 cost levels are not mandatory  
16 contributions, but these payments, however, do generally tend to increase the Company's  
17 pension asset, which tends to decrease future funding needed to cover the pension  
18 liability.

19  
20 **Q: WAS THE COMPANY ASKED TO PROVIDE SUPPORT FOR ITS STARTING**  
21 **BALANCE IN 2003 OF \$36,508,316?**

1 A: Yes. In the Company's Data Request 9-6, PSO was asked to provide support for its  
2 starting balance in prepaid pensions. In its response, the Company indicated that the  
3 information to support the beginning balance was unavailable.

4  
5 **Q: ARE THERE OTHER REASONS TO DISREGARD THE 2003 STARTING**  
6 **BALANCE?**

7 A: Yes. In the Company's 2003 rate case, Cause No. PUD 200300076, the utility used a  
8 test year of June 30, 2003 with a 6-month post-test year update period that ran through  
9 December 31, 2003. No prepaid pension asset was presented in that case. If there had  
10 been a prepaid pension asset in 2003, the time to include it in rate base would have been  
11 in that rate case.

12  
13 **Q: WHAT ADJUSTMENT ARE YOU PROPOSING?**

14 A: I am proposing to remove the 2003 starting balance of \$36,508,316 in the prepaid  
15 pension calculations. The necessary adjustment can be seen at *Exhibit MG-2.2*. The  
16 revenue requirement impacts of the adjustments are set forth in the table below:

<b>TABLE 2: Impact of OIEC's Pre-Paid Pension Adjustment</b>				
<b>Ln</b>	<b>Description</b>	<b>Adj.</b>	<b>ROR<sup>2</sup></b>	<b>Rev. Req.</b>
1	PSO Prepaid Pension Balance in Rate Base	(\$36,508,316)	10.318%	(\$3,766,782)

<sup>2</sup> OIEC's proposed rate of return grossed up for tax.

**II. C. DISALLOWED INCENTIVE PAYMENTS IN RATE BASE**

1 **Q: PLEASE EXPLAIN OIEC'S ADJUSTMENT FOR INCENTIVE PAYMENTS IN**  
2 **RATE BASE.**

3 A: Each year, PSO capitalizes a portion of its incentive plan payments. These payments are  
4 included in rate base where they earn a return. The Commission has consistently  
5 excluded 50% of PSO's short-term and 100% of the Company's long-term incentives  
6 from operating expense. In order to consistently apply the Commission's treatment of  
7 incentive compensation, the same portion of PSO's incentive payments excluded from  
8 operating expense for ratemaking purposes must also be excluded from rate base. If not,  
9 the Company will earn a return on, and eventually recover from ratepayers,  
10 compensation associated with incentive plans the Commission has disallowed. Thus,  
11 50% of the capitalized short term incentive payments and 100% of the capitalized long  
12 term incentive payments must be removed from rate base, for a total adjustment to rate  
13 base of \$37,645,259. This adjustment is necessary to make the Commission's treatment  
14 of incentive costs in rate base consistent with its treatment of PSO's incentive costs in  
15 operating expense in PSO's prior litigated cases, including PUD 200600285 and PUD  
16 200800144 and PUD 201500208.

17  
18 **Q: DID THE ALJ REJECT THE PROPOSED INCENTIVE ADJUSTMENT TO**  
19 **RATE BASE IN THE COMPANY'S LAST RATE CASE, PUD 201500208?**

20 A: Yes. However, the failure to remove capitalized incentives from rate base is completely  
21 inconsistent with the Commission's longstanding treatment of incentive compensation in

1 this state, where 50% of short-term and 100% of long-term incentives are disallowed. In  
2 fact, the decision to reject the rate base side of the incentive adjustment effectively  
3 circumvents the Commission's orders to disallow these costs.

4 **Q: IN YOUR EXPERIENCE, HOW DO OTHER STATES TREAT THIS**  
5 **ADJUSTMENT?**

6 A: Many states apply the incentive compensation adjustment to rate base. For example,  
7 Texas routinely adjusts rate base for disallowed incentives, as does Missouri.

8  
9 **Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT YOU PROPOSE?**

10 A: The rate base adjustment is set forth below and can be seen at *Exhibit MG-2.4*.

11 Rate Base Adjustment to Exclude Disallowed Capitalized Incentives **\$(37,645,259)**

### 12 **III. OPERATING EXPENSE ISSUES**

#### 13 **III. A. ANNUAL INCENTIVE COMPENSATION EXPENSE**

14 **Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF AEP/PSO'S ANNUAL**  
15 **INCENTIVE COMPENSATION PLANS.**

16 A: AEP/PSO's incentive compensation plans are formal, written plans approved by senior  
17 management. In total, there are four annual incentive plans under which PSO and  
AEPSC employees may be compensated. These plans are described in the direct  
testimony and exhibits of PSO witness Andrew R. Carlin. In this application, PSO seeks

1 to include \$9.098 million in rates for annual incentive expense, based upon the  
2 Company's *targeted* payout for incentive expense, according to the Company.<sup>3</sup>

3 **Q: DO FINANCIAL PERFORMANCE MEASURES COMPRISE THE MOST**  
4 **SIGNIFICANT COMPONENT OF PSO'S INCENTIVE COMPENSATION**  
5 **PLAN?**

6 A: Yes. PSO's 2016 Annual Compensation Plan is heavily dependent on financial  
7 performance measures. As in prior years, PSO's incentive plans are based upon various  
8 financial and operational measures, however, the overall funding available to pay annual  
9 incentive compensation is based 75% on AEP's earnings per share (EPS),<sup>4</sup> as it was in  
10 PSO's last rate case, PUD 201500208. In other words, even though the Company's  
11 performance measures include both financial and non-financial factors, the actual  
12 *funding* trigger for incentive compensation payments is primarily tied to the financial  
13 performance of the Company. Under the Company's funding mechanism, regardless of  
14 how well individual employees may perform in nonfinancial performance areas such as  
15 customer satisfaction and safety, if the Company's EPS is low, payments to employees  
16 will be reduced accordingly. If EPS falls below the stated minimum threshold, funding  
17 for the plan would be reduced to 0%, and thus, no incentive compensation would be  
18 paid, no matter how well individual employees performed on their stated objectives.  
19 Thus, under the Company's incentive compensation plan, corporate earnings is the  
20 primary driver in determining whether, and to what extent, incentive compensation will

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<sup>3</sup> The actual amount of incentive compensation the Company paid during the test year was higher than targeted levels. See PSO W/P H-2.6.

1 be paid each year. The Company admits that its annual incentive plan is tied to the  
2 “achievement of financial goals.”<sup>5</sup> Specifically, the Company’s 2016 Overview states,  
3 “Linking annual incentive compensation to AEP’s earnings aligns it with the value  
4 created for AEP’s shareholders and ensures that AEP meets its shareholder commitments  
5 before setting aside dollars for employee rewards.”<sup>6</sup>  
6

7 **Q: WHAT ADJUSTMENTS DO YOU PROPOSE WITH RESPECT TO THE**  
8 **COMPANY’S REQUESTED LEVEL OF ANNUAL INCENTIVE**  
9 **COMPENSATION EXPENSE?**

10 A: I am proposing to reduce the requested level of annual incentive expense to exclude the  
11 portion of the incentive plans related to financial performance measures. From my  
12 review of the plans, it is clear that the *funding* of the annual plans is triggered primarily  
13 based on the Company’s financial performance (75% EPS). As a result, I have reduced  
14 the Company’s requested level of annual incentive compensation of \$9,098,879 by 75%,  
15 or \$6,824,159.  
16

17 **Q: IS THIS TREATMENT CONSISTENT WITH THIS COMMISSION’S**  
18 **TREATMENT OF INCENTIVE COMPENSATION IN PRIOR CASES?**

19 A: Yes. In prior cases, the Commission has consistently reduced the requested levels of  
20 incentive compensation based upon the fact that the plans are tied to the Company’s  
21 financial performance. In PSO’s last three litigated rate cases, the Commission reduced

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<sup>4</sup> See Response to AG 3-21\_Att\_3.

<sup>5</sup> See Carlin Direct Testimony, p. 14, lines 21-23.

1 PSO's requested annual incentive compensation by 50% based upon the testimony and  
2 evidence in those proceedings that the plans were tied to financial performance.<sup>7</sup>

3 In PSO's 2006 rate case, PUD 200600285, the Commission disallowed 50% of  
4 AEP/PSO's annual incentive expense.<sup>8</sup>

5 The Commission finds that 50% of PSO's incentive costs should be excluded  
6 for ratemaking purposes, as recommended by OIEC. The amount of those  
7 incentive costs is \$3,454,217 as referenced in HE-17 at page 16 of 24, OIEC  
8 Adjustment No. H-4.

9 In PSO's 2008 rate case, PUD 200800144, the Commission again disallowed  
10 50% of AEP/PSO's annual incentive plan.<sup>9</sup>

11 The Commission finds that although there is no evidence to conclude  
12 PSO's and AEPSC's overall salary levels are excessive, that the  
13 recommendation of the AG and Staff to disallow 50% of PSO's and  
14 AEPSC's incentive compensation should be adopted. Incentive  
15 compensation benefits both shareholders and ratepayers equally, by  
16 encouraging the attainment of goals that provide good customer service  
17 and increase the earnings of the shareholders.

18 In PSO's last rate case, Cause No. PUD 201500208, the Commission's final  
19 order states the following with respect to incentive compensation:

20 The ALJ adopts Staff and AG's recommendation that an adjustment be  
21 made to remove the portion of the Annual Incentive Program costs related  
22 to financial performance measures. In many jurisdictions, including  
23 Oklahoma, the cost of incentive plans tied to financial performance  
24 measures generally are excluded for ratemaking purposes for several  
25 reasons. (See Garrett Responsive Testimony, pp. 23-33). The evidence in  
26 this case established that the Company's incentive compensation is funded

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<sup>6</sup> See Response to AG 3-17 Attachment p. 1.  
<sup>7</sup> Cause Nos. PUD 200600285, PUD 200800144, and PUD 201500208.  
<sup>8</sup> See Final Order in Cause No. PUD 200600285.  
<sup>9</sup> See Final Order in Cause No. PUD 200800144.

1 primarily based on the Company's financial performance (75% earnings  
2 per share). (See Garrett Responsive Testimony. p. 17).

3 . . . . .  
4 The result of the above disallowances reduces the recoverable expenses of  
5 PSO by . . . \$4,369,947 for short term incentive expense, which is 50% of  
6 the \$8,739,895 requested by PSO. (See Garrett Responsive Testimony.  
7 Ex. MG-2).

8 Similarly, in OG&E's last two litigated rate cases,<sup>10</sup> the Commission reduced  
9 OG&E's annual incentive plan costs for amounts tied to financial performance. In  
10 OG&E's last rate case, PUD 201500151, the requested amounts were reduced by 50%  
11 and in OG&E's 2005 rate case, PUD 200500151, the requested amounts were reduced  
12 by 60%.

13  
14 **Q: WHY HAVE YOU RECOMMENDED REDUCING RATE RECOVERY OF**  
15 **INCENTIVE COMPENSATION BY 75% RATHER THAN 50% IN THIS**  
16 **PROCEEDING?**

17 A: My recommendation is based upon the evidence presented by the Company, particularly  
18 the Company's admissions that: (1) the funding of the annual incentive compensation  
19 level is based 75% on AEP's earnings per share (EPS),<sup>11</sup> and (2) the payment of  
20 incentive compensation is wholly at the *discretion* of management each year.<sup>12</sup> In fact,  
21 the AEP 2016 Plan states the following:

22 **2016 Funding Measures**

23 The 2016 funding measures were established by the HR committee of the  
24 Board early in the year. The maximum available funding for 2016 is

---

<sup>10</sup> Cause Nos. PUD 201500273 and PUD 200500151.

<sup>11</sup> See PSO's response to Data Request AG 3-17\_Attachment at page 3.

<sup>12</sup> See PSO's response to Data Request AG 3-17\_Attachment at page 2.

1 200% of target funding. As in past years, the CEO and HR Committee of  
2 the Board have discretion to adjust annual incentive funding. All  
3 incentive plan funding is contingent on AEP achieving operating  
4 earnings of at least \$3.65 per share for 2016.<sup>13</sup>

5 **Operating Earnings per Share - 75%**

6 AEP is committed to generating sustainable value for its shareholders  
7 through its earnings and growth. Therefore 75% of annual incentive  
8 funding is tied to AEP's Operating Earnings per Share. This ensures that  
9 funding is commensurate with the Company's operating earnings and the  
10 extent to which the company can afford to pay annual incentive  
11 compensation while also serving the interests of its shareholders,  
12 customers and other stakeholders. It also:

- 13 • Further aligns the financial interests of all AEP employees with  
14 those of AEP's shareholders;
- 15 • Ensures that adequate earnings are generated for AEP's  
16 shareholders and continued investment in AEP's business before  
17 employees are rewarded with annual incentive compensation; and
- 18 • Aligns employee interests with those of regulated and other  
19 customers by strongly encouraging expense discipline.<sup>14</sup>

20 The language of the Plan makes clear four important points:

- 21 (1) Funding of the Plan is based 75% on Earnings per Share;
- 22 (2) Funding is wholly within the discretion of the CEO and HR committee;
- 23 (3) This approach aligns the financial interests of employees and shareholders;
- 24 (4) And, it assures that its shareholders are taken care of first, before its employees.

25 **Q: WHAT IS THE GENERAL RATIONALE FOR EXCLUDING INCENTIVE**  
26 **COMPENSATION TIED TO FINANCIAL PERFORMANCE?**

27 **A:** As a general rule, the cost of incentive plans tied to financial performance measures are

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<sup>13</sup> See PSO's response to Data Request AG 3-17\_Attachment at page 2 (emphasis added).

<sup>14</sup> See PSO's response to Data Request AG 3-17\_Attachment at page 3 (emphasis added).

1 excluded from rates.<sup>15</sup> When the costs associated with these plans are excluded, the  
2 rationale is generally based on one or more of the following reasons:

3 (1) **Payment is uncertain.** Often, payment of incentive compensation is conditioned  
4 upon meeting some predetermined financial goal such as achieving a certain  
5 increase in earnings, reaching a targeted stock price or meeting budget objectives.  
6 If the predetermined goals are not met, the incentive payment is not made, or  
7 payment is made at some lesser amount. Therefore, one cannot know from year  
8 to year what the level of the payment may be or whether the payment will be  
9 made at all. It is generally considered inappropriate to set rates to recover a  
10 tentative level of expense.<sup>16</sup>

11 (2) **Many of the factors that significantly impact earnings are outside the control**  
12 **of most company employees and have limited value to customers.** For  
13 example, an unusually hot summer can easily trigger an incentive payment based  
14 on company earnings for an electric utility. Obviously, weather conditions are  
15 outside the control of utility employees and customers receive no benefit from  
16 the higher utility bills that result from an unusually hot summer. Similarly,  
17 company earnings may increase, thus triggering incentive payments, as a result of  
18 customer growth, which commonly occurs without significant influence from  
19 company personnel. In fairness, since shareholders enjoy the benefits of  
20 customer growth between rate cases, shareholders should also bear the cost of  
21 any incentive payments such growth may trigger. Finally, utility earnings may  
22 increase substantially if the utility is able to successfully argue for a higher ROE  
23 in a rate case proceeding. Utility efforts to maximize ROE in a rate proceeding,  
24 however, have little to do with improving overall employee performance across  
25 the company. If utility employees gear their efforts toward securing an  
26 *unreasonably* high ROE in a rate proceeding, the incentive mechanism actually  
27 would work to the detriment of the utility customers.

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<sup>15</sup> See the results of the Survey of Western States outlined below. Also, see for example, *U.S. West Communications, Inc. v. Public Service Comm'n*, 901 P.2d 270, 276-77 (Utah 1995); *Central Illinois Public Service Company Proposed General Increase In Natural Gas Rates*, Docket No. 02-0798 (Cons.), 2003 Ill. PUC LEXIS 824, p. 115 (Illinois Commerce Comm'n 2003); *Application of Wisconsin Power and Light Company as an Electric, Natural Gas and Water Utility for Authority to Change Electric, Natural Gas, and Water Rates*, Docket No. 6680-UR-113, 2003 Wisc. PUC LEXIS 822, pp. 40-41 (Wisconsin Public Service Comm'n 2003); *Petition of Northern States Power Company's Gas Utility for Authority to Change its Schedule of Gas Rates for Retail Customers Within the State of Minnesota*, 146 P.U.R.4th 1, pp. 40-43 (Minnesota Public Util. Comm'n 1993); *Application of Minnegasco, a Division of NorAm Energy Corp., for Authority to Increase its Natural Gas Rates in Minnesota*, 170 P.U.R.4th 193, pp. 69-77 (Minnesota Public Util. Comm'n 1996).

<sup>16</sup> PSO's experience in the 2008 rate case is a good example of this problem. In 2009, AEP's below target EPS reduced the funding available for incentive compensation payments by 76.9%. Although in the Company's 2008 rate case, the Commission had included more than \$4 million in rates for incentives, the Company chose not to use all of that money to pay incentives but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

1           (3)   **Earnings-based incentive plans can discourage conservation.** When incentive  
2           payments are based on earnings, employees may not support conservation  
3           programs designed to reduce usage if they perceive these programs could  
4           adversely impact incentive payment levels. To the extent that earnings-based  
5           incentive plans discourage conservation and demand-side management programs,  
6           these plans do not serve the public interest. The growing focus on energy  
7           efficiency at both the national and state level renders this point especially  
8           important.

9           (4)   **The utility and its stockholders assume none of the financial risks associated**  
10          **with incentive payments.** Ratepayers assume the risk that the utility will instead  
11          retain the amounts collected through rates for incentive payments whenever  
12          targeted increases are not reached. Employees assume the risk that the incentive  
13          payments will not be made in a given year. The utility and its stockholders,  
14          however, assume no risk associated with these payments. Instead, the company's  
15          only responsibility is to decide who gets the money, the stockholders or the  
16          employees.<sup>17</sup>

17          (5)   **Incentive payments based on financial performance measures should be**  
18          **made out of increased earnings.** Whatever the targets or goals may be that  
19          trigger an incentive payment, when the plan is based in whole or in part on  
20          financial performance measures the company always obtains a financial benefit  
21          from achieving these objectives. This financial benefit should provide ample  
22          funds from which to make the payment. If not, the incentive plan was poorly  
23          conceived in the first place. As such, employees should be compensated out of  
24          the increased earnings, and not through rates.<sup>18</sup>

25          (6)   **Incentive payments embedded in rates shelter the utility against the risk of**  
26          **earnings erosion through attrition.** When utilities are allowed to embed  
27          amounts for incentive payments in rates, that money is available to the utility not  
28          only to pay the incentive payment when financial performance goals are met but  
29          also to supplement earnings in those years when the company does not perform  
30          well. In those years when financial performance measures are met, the increased  
31          earnings of the company provide ample additional funds from which to make the  
32          incentive payments to employees, and the incentive payment amount embedded  
33          in rates is not needed. In those years when financial performance measures are  
34          not met and the incentive payments are not made, the amount embedded in rates

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<sup>17</sup> This occurred in PSO's 2008 rate case. In 2009, when AEP's EPS fell below targeted levels, the Company simply retained for its stockholders the funds that had been provided in rates for incentive plans.

<sup>18</sup> The fact is, AEP/PSO only makes incentive payments each year to the extent its earnings are sufficient to cover the costs of the payments. See Response to AG 3-17, Attachment p. 1, in which the Company's 2016 Plan states, "Linking annual incentive compensation to AEP's earnings aligns it with the value created for AEP's shareholders and ensures that AEP meets its shareholder commitments before setting aside dollars for employee awards."

1 for incentive payments acts as a financial hedge to shelter the poor financial  
2 performance of the company.

3 **Q: THE COMPANY ASSERTS THAT ITS VARIABLE COMPENSATION PLAN IS**  
4 **CUSTOMARY FOR MANY INDUSTRIES INCLUDING UTILITIES, AND**  
5 **THAT SUCH PLANS ARE EFFECTIVE FOR MOTIVATING EMPLOYEE**  
6 **PERFORMANCE. ARE YOU RECOMMENDING THAT THE COMPANY**  
7 **CHANGE ITS COMPENSATION STRUCTURE?**

8 **A:** No, not at all. Even though regulators routinely exclude financial-based incentive  
9 compensation payments based on one or more of the reasons outlined above, this does  
10 not mean that regulated companies will not continue to offer financial-based incentives.  
11 They continue to do so, because it furthers key corporate goals. For example, AEP's  
12 2016 Plan states that it is designed to "foster the creation of sustainable shareholder  
13 value through achievement of AEP's goals."<sup>19</sup> Moreover, AEP's objective is clear,  
14 **"Linking annual incentive compensation to AEP's earnings aligns it with the value**  
15 **created for AEP's shareholders and ensures that AEP meets its shareholder**  
16 **commitments before setting aside dollars for employee awards."**<sup>20</sup> When such  
17 financial-based incentive packages are properly constructed, however, there will be  
18 ample increased earnings to fund these payments to utility employees. Thus, ratepayers  
19 do not need to subsidize incentive compensation plans that are designed to enhance the  
20 Company's financial performance, and to align the employees' interests with the  
21 shareholders

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<sup>19</sup> See Response to AG 3-17\_ Attachment p. 1.

<sup>20</sup> Id. (emphasis added).

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**Q: WHY IS THE DISTINCTION BETWEEN FINANCIAL PERFORMANCE MEASURES AND CUSTOMER SATISFACTION AN IMPORTANT DISTINCTION FOR INCENTIVE COMPENSATION ANALYSIS?**

A: When incentive compensation payments are based on financial performance measures, the compensation agreement between shareholders and employees could be loosely stated in this manner: “if you increase shareholder earnings, we will pay you a bonus.” The intended beneficiaries to this agreement are the shareholders and the employees. Ratepayers have no stake in this agreement; therefore, they should bear none of the costs that result from such an agreement. If, instead, the agreement was stated in this manner: “if you increase reliability and quality of service to the customers, we will pay you a bonus,” then, ratepayers would have a stake in the agreement, and could share in a portion of the costs. However, so long as the overriding goal of the incentive plan is to increase shareholder earnings, the entire incentive compensation should be funded out of the increased earnings that trigger the payments.

**Q: HOW DO OTHER JURISDICTIONS TREAT INCENTIVE COMPENSATION?**

A: The results of an Incentive Compensation Survey of the 24 Western States taken by the Garrett Group in 2007, and updated in 2009, 2011, and 2015, shows that a clear majority of the states follow the financial-performance rule, in which incentive payments associated with financial performance are excluded from rates. Some states disallow incentive pay using other criteria. None of the jurisdictions surveyed allow full recovery

1 of incentive compensation through rates as a general rule. The results of the survey are  
2 set forth below.

3 **States that follow the Financial-Performance Rule:**

4 **Arizona** The Commission deals with incentive compensation plans on a case by  
5 case basis. Evaluation centers on the criteria of benefit to customers.  
6 This treatment tends to make long-term programs harder to justify, but the  
7 same criteria are used to evaluate all plans including those for  
8 executives.<sup>21</sup> In practice, this means that the costs of long-term plans are  
9 generally excluded altogether and the costs of the short term annual cash  
10 plans are shared 50/50 between shareholders and ratepayers.<sup>22</sup>

11 **Arkansas** Generally excludes 100% of the long-term, equity-based plans. Short-  
12 term incentive plans are evaluated to determine if they are based on  
13 financial or operational measures. Operational-based plans are allowed.  
14 50% of plans containing financial measures are disallowed. Any plans  
15 based solely on the discretion of the company are seen as having no direct  
16 benefit to ratepayers and are disallowed 100%. Settlements have also  
17 followed this treatment.<sup>23</sup> Commission rulings on Incentive  
18 Compensation have remained generally consistent, excluding 100% of  
19 long-term plans and 50% of the portion of short-term plans that are  
20 financially based. In the Entergy rate case (Docket No. 13-028-U), 50%  
21 of all short-term incentive compensation was excluded because the plans  
22 included a financially-based multiplier.

23 **California** The Commission has established precedence for evaluating plans based  
24 on who benefits from the plans goals, ratepayer or shareholders. In  
25 CPUC Decision 00-02-046, the Commission established that utilities  
26 could recover 50% of the regular employee's incentive compensation  
27 costs in rates. In the Southern California Edison litigated rate case  
28 Decision 09-03-025, the Commission decided that Edison's non-

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<sup>21</sup> See Epcor Water, Docket No. WS-01303A-14-0010. See also APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.

<sup>22</sup> See e.g., APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011. See also Staff's testimony in the 2016 APS rate case, Docket No. E-1345A-16-0036.

<sup>23</sup> Entergy Arkansas, Docket No. 06-101-U, Order No. 10 and Docket No. 13-028-U, Order No. 21.

1 executive plans and 50% of the short-term executive plans would be  
2 funded in rates and that 100% of the executive long-term stock plans  
3 would be disallowed.<sup>24</sup> In cause number A.10-07-007, staff  
4 recommended that, "customer funding should be limited to the portion of  
5 the incentive plan payments that are aligned with operational objective  
6 that provide customer benefits. This means that 70% of AIP be funded by  
7 shareholders, and 30% be funded by ratepayers." Pursuant to settlement  
8 of the parties, the Commission disallowed 50% of the plan's expense.

9 **Hawaii** Incentive compensation of all types is excluded from rates. The  
10 Commission upholds the position stated in Docket No. 6531 that  
11 incentives tied to company income and earnings benefit stockholders, not  
12 ratepayers. The Commission further stated, "...we believe that a utility  
13 employee, especially at the executive level, should perform at an  
14 optimum level without additional compensation. Ratepayers should not  
15 be burdened with additional costs for expected levels of service."<sup>25</sup>  
16 Utilities in Hawaii no longer petition to have incentive compensation  
17 expense included in rates.

18 **Idaho** The Commission's policy for evaluating incentive compensation plans  
19 involves determining who benefits, the customer or the company. This  
20 treatment was refined in the Idaho Power rate case, IPC-E-08-10, for  
21 plans which benefit the customer but require a financial trigger to be paid.  
22 For these plans the Commission reduced the percentage allowed in rates.  
23 The Commission does not include executive compensation in rates.<sup>26</sup>

24 **Kansas** For officer level incentives plans, the financially-based portion is borne  
25 by the shareholders and the portion supporting operational goals is  
26 allowed in rates. Non-officer incentive compensation plans for workers  
27 are allowed in rates.<sup>27</sup> The consumer advocacy branch, Citizens' Utility

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<sup>24</sup> Southern California Edison (Application No. 07-11-011; Decision No. 09-03-025).

<sup>25</sup> Hawaii's policy is set forth in Docket No. 6531 in the October 17, 1991 Order No. 11317. Prior Dockets in which the Commission disallowed incentive compensation include No. 3216, No. 4215, No. 4588 and No. 5114.

<sup>26</sup> The Commission's focus on customer benefit is reflected in the direct testimony of Staff witness Leckie, and in the Final Order in IPC-E-08-10. For earlier examples of the basic policy, see Idaho Power Company Rate Case IPC-E-05-28, Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28, Order No. 30035, p. 4/10.

<sup>27</sup> This treatment is based on the 2012 KCPL rate case (12-KCPE-764-RTS) in which the short-term plan was split 50:50, and for the long-term incentives, the Commission excluded 100% of the portion based on

1 Ratepayer Board (CURB) has consistently recommended applying the  
2 same financial/operational criteria to non-officer plans as well. In the  
3 current KCPL rate case the company has voluntarily excluded 100% of  
4 the performance-based plans and 50% of the short-term plans with an  
5 earnings-per-share qualifier. The Company also removed the earnings-  
6 per-share portion of their plan for all employees.

7 **Louisiana** Traditionally incentive compensation for upper level management and  
8 officers is excluded, while costs for lower level managers and employees  
9 are allowed. The criteria used to evaluate plan design consider whether  
10 the goals of each plan directly benefit ratepayers or shareholders. Stock  
11 based compensation plans at all levels are excluded.

12 **Minnesota** Minnesota continues to distinguish between incentive plans tied to  
13 financial triggers (such as a threshold ROE) and plans tied to criteria  
14 benefitting the ratepayer. Plans based on goals which benefit ratepayers  
15 are generally allowed in rates, but their costs are frequently capped at a  
16 percentage of base salaries such as 15% or 25%.<sup>28</sup> Utilities are usually  
17 required to return to ratepayers any portion of incentive pay that was  
18 allowed into rates and is not subsequently paid out to employees.  
19 Executive and long-term IC measures are frequently more closely aligned  
20 with shareholder interests and thus are not usually allowed in rates.<sup>29</sup>

21 **Missouri** Plans are analyzed to determine who benefits. Plans that can show a  
22 direct benefit to customers and that are found to be prudent are allowed in  
23 rates. Plans that benefit shareholders are excluded. The Commission also  
24 allows only the amounts actually paid, not those accrued. The same  
25 criteria are used for executive plans and few are allowed.<sup>30</sup>

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stockholder return and 50% of the time-based restricted stock portion of the plan. Time-based plans which vest solely on the passage of time are seen as being neutral and therefore split 50:50 between shareholders and ratepayers.

<sup>28</sup> This general policy is demonstrated in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively.

<sup>29</sup> Minnesota's general policy is demonstrated in CenterPoint Energy rate case G-008/GR-13-316 and the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively. See also Minnesota Power General Rate Case E002/GR/05/1428.

<sup>30</sup> See e.g., in the Missouri American rate case (WR-2010-0131), not only were plans based on financial goals disallowed, but incentive payments based on customer satisfaction were disallowed due to the unreasonably small sample size used to establish a positive rating (a phone survey of 927 of roughly 450,000 customers). The Commission also removed incentive payments tied to lobbying and charitable activity. In the subsequent

1           **Montana**       Due to the low volume of litigated cases in the past 10 to 15 years in  
2 Montana, incentive compensation has not been an important issue before  
3 the Commission. However, the Commission tends to become more  
4 concerned by incentive plans that are tilted toward financial performance  
5 instead of operational goals.

6           **Nebraska**      Nebraska does not have rules regarding incentive compensation and  
7 considers the issue on a case by case basis. In a 2007 rate case, NG-0041,  
8 the Commission disallowed 50%, directing that cost should follow benefit  
9 and stating, "However, the Commission further finds that the nature of the  
10 objectives appear to benefit both ratepayers and shareholders and it would  
11 be improper for the ratepayers to bear the full cost of this benefit." The  
12 Commission also allowed in rates only the actual amounts paid. In NG-  
13 0060 the Commission disallowed the entire amount requested by  
14 SourceGas for cash incentives.

15          **Nevada**        The Commission excludes 100% of the long-term plans and all short-term  
16 plan costs directly related to financial performance.<sup>31</sup> Utilities in Nevada  
17 generally do not seek to include long-term incentives in rates.

18          **New Mexico**   Incentive programs tied to measures that benefit ratepayers (such as  
19 operation and safety) are allowed in rates. Programs tied to the financial  
20 performance of the utility (e.g. stock price or ROE) are not allowed in  
21 rates. This standard is applied to all levels of utility employees and tends  
22 to eliminate the greater portion of executive plans.<sup>32</sup> Executive incentive  
23 plans receive more scrutiny as they are more likely to have financial  
24 measures. They can also be challenged if the overall percentage is out of  
25 line. One major utility in New Mexico no longer includes the  
26 compensation of its top 5 executives in rate applications.

27          **N. Dakota**     In North Dakota, the general policy is the portion that relates to earnings  
28 of the shareholders is disallowed and the rest is included. In the past, the  
29 Commission has limited incentives to 15% of salary. The general

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Ameren UE rate case, the company did not seek even short-term incentive compensation tied to earnings, providing further indication that staff's practice of disallowing financial performance based incentives is accepted by the companies. All incentive compensation adjustments were made not only to expense charges, but to construction charges as well. *See also* Kansas City Power and Light and Empire Electric District orders on the Commission's website.

<sup>31</sup> *See e.g.*, PUCN's final order in Docket 11-06006.

<sup>32</sup> *See* Docket 07-00077-UT.

1 approach is to determine if incentive compensation is reasonable and fair  
2 based on market analysis. Historically, executive incentive compensation  
3 is not allowed in rates, and is typically not sought by the company.

4 **Oklahoma** The Commission excludes incentive payments tied to financial  
5 performance. From a practical perspective this means that all long-term  
6 plans are excluded and some portion of the annual short-term cash plan  
7 are excluded. The Commission does not determine the precise portion of  
8 the annual plans tied to financial measures but instead excludes 50% of  
9 the annual plans. 100% of the long-term executive stock-based plans are  
10 excluded.<sup>33</sup> In some instances, the Commission allows gas utilities with  
11 formula rates plans that share excess earnings with customers to include  
12 incentives in rates.

13 **Oregon** The Commission's general policy is based on the idea that customers  
14 should not have to pay for incentive compensation based on financial  
15 goals such as rate of return. For short-term plans, the portion based on  
16 financial measures is excluded from rates. The only long-term plans are  
17 for officers, and 100% of officer incentives are excluded from rates.

18 **S. Dakota** South Dakota considers incentive compensation on a case by case basis.  
19 Their general policy is to evaluate each plan and disallow the portion  
20 based on financial performance indicators. This treatment is set forth in  
21 EL14-026 in which the order specifically excluded the amount "tied to the  
22 Company's financial results."<sup>34</sup> Current treatment also includes  
23 disallowing both executive and non-executive management incentive  
24 compensation. Several utilities have whole incentive programs that hinge  
25 on whether or not the company earns a certain return. These financial  
26 prerequisites cause the whole plans to be excluded from rates.

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<sup>33</sup> See e.g., AEP-PSO Cause Nos. PUD 06-285, PUD 08-144, and PUD 15-208; OG&E Cause Nos. PUD 05-151 and PUD 15-273; and ONG Cause No. PUD 04-610.

<sup>34</sup> In Docket No. EL 08-030 the settlement excluded bonuses related to "stockholder-benefitting financial goals." The settlement in Xcel rate case Docket No. EL09-009 removed payments based on financial performance indicators. In the settlement agreement signed July 7, 2010 in the Black Hills Power rate case Docket No. EL09-018 the *Staff Memorandum* states, "The settlement removes financial based incentive payments that were included in the capitalized labor costs for plant. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation."

1           **Texas**           The well-established precedent in Texas is that incentive payments  
2                               designed to improve financial performance are excluded.<sup>35</sup> In the recent  
3                               Southwestern Public Service Company (“SPS”) rate case, Docket No.  
4                               43695, the Texas Public Utility Commission disallowed 100% of the  
5                               short-term incentives directly tied to financial performance measures and  
6                               50% of the remaining incentives because they were indirectly tied to  
7                               financial performance through an earnings-per-share funding  
8                               mechanism.<sup>36</sup> Long-term stock incentives are excluded.<sup>37</sup> At the Rail  
9                               Road Commission, financial incentives are generally excluded and  
10                              customer-related incentives are allowed. Examples include: Atmos 9670  
11                              Order and Order on Rehearing, Texas Gas Service Company 9988 Final  
12                              Order, Centerpoint 9902 Final Order and Centerpoint 10106 Final Order.  
13                              In Docket 9670, both the executive and employee plans for Atmos Mid-  
14                              Tex were found not to be just and reasonable because they, "advanced the  
15                              interest of shareholders, and [are] driven by Company earnings." None of  
16                              the costs of these programs were allowed in rates. In TGS Docket 9988,  
17                              the RRC found 100% of long-term and 90% of short-term incentives  
18                              expense was "unreasonable" because it was related to the financial  
19                              performance of ONEOK Inc. 10% of the short-term plan was allowed in  
20                              rates because it was based on safety metrics.

21           **Utah**            The Commission’s general policy is to allow in rates the parts of a plan  
22                               that are tied to ratepayer benefit and disallow the parts tied to financial  
23                               goals. Equity-based incentive compensation is excluded from rates.<sup>38</sup>

24           **Washington**   Incentive plans are evaluated on a case by case basis. Incentives tied to  
25                               operational efficiency or other measures which benefit ratepayers are

<sup>35</sup> See *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Proposal for Decision at 92-97, Findings of Fact Nos. 164-170, Order at 35 (Aug. 15, 2005); *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 116-121, Finding of Fact No. 82, Order on Rehearing at 12 (March 4, 2008); *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100, Finding of Fact No. 93, Order on Rehearing at 22 (Nov. 30, 2009); and *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 66-67, Findings of Fact Nos. 81-83, Order on Rehearing at 22 (June 23, 2011).

<sup>36</sup> See Docket No. 43695, Order on Rehearing at 5-6.

<sup>37</sup> See Docket No. 39896 where the PUC disallowed \$730,734 in Entergy’s rate case expense for including Long-Term incentives in its rate application.

<sup>38</sup> The final order in Docket 09-035-23 follows this general policy as does the order in Docket 07-35-93. See also Missouri Corp. Rate Case Docket 97-035-01, pp. 10-12; US West Communications Rate Case Docket 95-049-05.

1 allowed in rates and incentives based on return on earnings or other  
2 measures that benefit the shareholders are disallowed.<sup>39</sup>

3 **Wyoming** Historically, employee incentive compensation plans are evaluated on a  
4 case by case basis, distinguishing between employee programs that  
5 benefit the ratepayer or the stockholders and requiring the benefitting  
6 party to pay. Executive incentive compensation plans are generally  
7 excluded from rates.

8 **States that use another approach:**

9 **Alaska** Incentive compensation is not an issue in rate cases in Alaska. There is  
10 no relevant regulation or policy.

11 **Colorado** Executive incentives are excluded from rates and typically no longer  
12 sought in company filings. With respect to annual incentive pay (AIP),  
13 Colorado used to evaluate incentive plans based on which stakeholder  
14 group benefited from the goals of a plan. In Public Service Company of  
15 Colorado, however, staff recommended that the Commission, "limit  
16 reimbursement of incentive pay to no more than 15 percent of employee  
17 base salary." In this proceeding, No. 14AL-0660E / Order C15-0292, the  
18 Settlement Agreement included the statement, "the Settling Parties agree  
19 AIP incentive payment recovery in the 2017 Rate Case will be capped at  
20 15% of an employee's salary."

21 **Iowa** Incentive Compensation has not been an issue in Iowa. There are no  
22 specific treatments in place and the Commission will review the merits  
23 and prudence of a proposed plan on a case-by-case basis.

24 **Q: IN YOUR EXPERIENCE, WHEN REGULATORS EXCLUDE THE PORTION**  
25 **OF A UTILITY'S INCENTIVE PLAN TIED TO FINANCIAL PERFORMANCE**  
26 **MEASURES, DOES THE UTILITY STOP OFFERING INCENTIVE**  
27 **COMPENSATION TO HELP ACHIEVE ITS FINANCIAL GOALS?**

28 No. Even though regulators generally disallow incentive compensation tied to financial  
29 performance for ratemaking purposes, utilities continue to include financial performance

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<sup>39</sup> See the Order in Pacific Power and Light Docket 061546.

1 as a key component of their plans. In my opinion, utilities continue to tie incentive  
2 payments to financial performance because by doing so they achieve the primary  
3 objective of the incentive plans: to increase corporate earnings and, thereby, earnings per  
4 share (EPS). However, since the utility retains the increased earnings these plans help  
5 achieve, payments for the plans should be made from these increased earnings. Thus,  
6 properly designed incentive compensation plans need not be subsidized by ratepayers.  
7

8 **Q: UNDER THE COMPANY'S 2016 INCENTIVE PLAN, IS ANNUAL PAYMENT**  
9 **UNCERTAIN AND DEPENDENT UPON FINANCIAL PERFORMANCE OF**  
10 **THE COMPANY?**

11 **A:** Yes. According to the Company, the incentive award payouts for each year can range  
12 from 0 percent to 200 percent of the target payout, based on AEP's financial  
13 circumstances.<sup>40</sup> Because the funding mechanism for incentive compensation is  
14 primarily calculated based on AEP's EPS, the Company may significantly reduce  
15 incentive payments, or make no incentive payments at all, if the threshold EPS goals are  
16 not met. In these situations, amounts collected through rates for incentive programs  
17 would be retained by the shareholders.

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<sup>40</sup> See Carlin Direct Testimony, p. 21, lines 7-8, and lines 21-22. See also, PSO's Response to OIEC's Fourth Data Request, Questions 5, 6 and 7.

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**Q: HAS PSO REDUCED ITS OVERALL INCENTIVE COMPENSATION LEVELS BASED UPON FINANCIAL PERFORMANCE MEASURES IN THE PAST?**

A: Yes. In 2009 the Company reduced its targeted payouts by 76.9% due to financial performance shortfalls during the year. Although the Commission had included more than \$4 million in rates for incentives in the Company's 2008 rate case, the Company chose not to use all of that money to pay incentives, but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

**Q: WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S INCENTIVE COMPENSATION EXPENSE?**

A: For ratemaking purposes, *all* of the cost of the AEP/PSO incentive plans could be excluded, based on the fact that these plans are overwhelmingly weighted toward the Company rather than customer objectives. In particular, because the *funding* of the plan depends on meeting the Company's financial EPS objectives, the Company effectively retains the incentive money for shareholders to the extent shareholder value objectives are not met each year. All of the incentive payments could also be excluded using the rationale of the Hawaii commission--that ratepayers should not be forced to pay additional incentives on top of normal payroll costs to get monopoly utility employees to show up and do their jobs. The Hawaii approach would result in a **100% disallowance**.

If, from a policy perspective, the Commission wants to encourage a focus on customer concerns, the Commission could include that portion of the plan costs that

1 purports to be representative of customer service and reliability goals, which would be  
2 about 20% of the costs of the plan. This percentage was calculated using OIEC 9-3\_Att1  
3 and OIEC 9-3\_Att2, comparing the payments made for customer service and reliability  
4 goals with total payments. This approach would result in an **80% disallowance**.

5 The Commission could also exclude all incentives tied to financial performance  
6 through the EPS funding mechanism. This would result in a **75% disallowance**.

7 The Commission could also follow the approach taken by the Texas PUC in the  
8 recent SPS case where all incentives directly tied to financial performance are excluded  
9 and 50% of the incentives indirectly tied to financial performance through an EPS  
10 funding mechanism are also excluded. The calculations for this approach are set forth at  
11 Exhibit MG2.4. The Texas approach results in a **60% disallowance**.

12 Or, the Commission could continue to use the approach it has used in the past  
13 where short-term incentives are shared 50/50 between ratepayers and shareholders. This  
14 approach results in a **50% disallowance**.

15 In my opinion, the Commission has several options available that range from a  
16 50% to a 100% disallowance. My recommendation of a 75% disallowance is in the  
17 middle of this available range of options.

18  
19 **Q: ARE THERE OTHER REASONS THE COMMISSION WOULD BE JUSTIFIED**  
20 **IN DISALLOWING 100% OF THE SHORT TERM INCENTIVE COSTS?**

21 **A:** Yes. In those areas where incentive costs could be allowed in rates—such as customer  
22 service and satisfaction—PSO is performing below average based on independent

1 customer surveys. In fact, PSO's JD Power Customer Satisfaction ratings were far  
2 below average in 2016, as were the ratings of most AEP operating companies. This begs  
3 the questions whether PSO ratepayers should be paying any portion of the incentive  
4 payments to PSO and AEPSC related to customer service goals when independent  
5 customer surveys indicate both PSO and AEPSC are performing well below average in  
6 these areas.

7  
8 **Q: WILL AEP BE FINANCIALLY HARMED FROM YOUR RECOMMENDATION**  
9 **TO EXCLUDE INCENTIVE COMPENSATION PAYMENTS?**

10 A: No. AEP/PSO's incentive compensation payments are discretionary payments limited  
11 by the Company's EPS funding mechanism. In those years when the EPS targets are  
12 achieved, the additional funds needed to make the incentive payments to employees will  
13 have been made available through the increased earnings that resulted from reaching  
14 these EPS goals. In fact, the funding mechanism ensures that the incentive payments are  
15 not made at the expense of the Company's shareholders. The 2016 Plan actually states  
16 under the 2016 Funding Mechanism section at page 2 of the plan that the funding  
17 mechanism:

18 Ensures that adequate earnings are generated for AEP's shareholders and  
19 continued investment in AEP's business before employees are rewarded  
20 with annual incentive compensation. (Emphasis added).

21 **Q: WHAT RATIONALE DOES THE COMPANY PROVIDE FOR INCLUDING ITS**  
22 **ANNUAL INCENTIVE PLAN IN RATES?**

1 A: The Company argues that incentives are part of a total compensation package that is  
2 designed to attract and retain qualified personnel. Since other utilities offer incentive  
3 plans to their employees, the Company would run the risk of not being able to compete  
4 for key personnel if it did not offer a comparable plan.<sup>41</sup>

5  
6 **Q: IS THIS ARGUMENT PLAUSIBLE?**

7 A: No. The problem with the Company's argument is that when utilities such as PSO  
8 compete with other utilities for qualified personnel, and the incentive compensation  
9 plans of these other utilities are being disallowed, for ratemaking purposes, for the  
10 portion of the plans tied to financial performance, PSO is not put at a competitive  
11 disadvantage when its incentive compensation costs are similarly disallowed.

12 Further, when incentive payments are based on financial performance goals,  
13 there should be a financial benefit to the company that comes from achieving these goals  
14 and this financial benefit should provide ample additional funds from which to make the  
15 incentive payments. Thus, a utility is not placed at a competitive disadvantage when  
16 incentive payments tied to financial performance are not collected through rates.

17

18 **Q: HAVE YOU REVIEWED THE TESTIMONY OF PAULINE M. AHERN**  
19 **REGARDING INCENTIVE COMPENSATION?**

20 A: Yes. Witness Pauline M. Ahern is a cost of capital witness who echoes several of the  
21 positions asserted by Mr. Carlin regarding incentive compensation. Essentially, Ms.

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<sup>41</sup> See Carlin Direct Testimony, p. 4, lines 2-9; p. 5, lines 6-9, p. 11, lines 16-20.

1 Ahern takes the position that paying incentives is standard practice for utilities,<sup>42</sup> that if  
2 these costs are not fully recovered in rates the utility will earn a lower return (assuming it  
3 continues to pay the costs), and as a result, the Company will not be able to attract  
4 capital at the best rates possible.<sup>43</sup>

5  
6 **Q: DO YOU THINK THIS COMMISSION SHOULD GIVE HER TESTIMONY ANY**  
7 **WEIGHT?**

8 A: No, for several reasons. First, Ms. Ahern provides no support for any of her opinions  
9 regarding incentive compensation. Further, Ms. Ahern is a cost of capital expert, she is  
10 not a ratemaking expert nor is she a compensation expert. She is not qualified to render  
11 opinions on the ratemaking treatment of incentives or other compensation costs.  
12 Moreover, her conclusions are illogical. While it may be true that most utilities make  
13 incentive compensation payments to employees, it does not follow that these payments  
14 should be recovered in rates. While it is true that most utilities make these payments, it  
15 is also true that most utilities do not fully recover those costs in rates. Thus, PSO is not  
16 disadvantaged when it is treated similarly to other utilities in this regard for ratemaking  
17 purposes. The same is true for many other costs such as lobbying expenses, charitable  
18 contributions, and promotional advertising. Using Ms. Ahern's logic, these costs too  
19 should be included in rates. Like incentive payments, though, utilities all incur these  
20 costs but they do not recover them in rates a general rule. Finally, Ms. Ahern makes no  
21 attempt to quantify the higher capital costs that would supposedly result from these

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<sup>42</sup> Ahern Direct Testimony at page 16, lines 10-13.

<sup>43</sup> Ahern Direct Testimony at page 25, lines 6-10.

1 disallowances. To make her arguments plausible, these purported additional capital  
2 costs would need to be high enough to offset the lower rates that result from the  
3 disallowance of incentive compensation.  
4

5 **Q: HAVE YOU REVIEWED THE TESTIMONY OF DAVID J. WATHEN**  
6 **REGARDING INCENTIVE COMPENSATION?**

7 A: Yes. Mr. Wathen is a consultant employed by Willis Towers Watson that offers  
8 testimony on behalf of the Company in this case. His testimony echoes several positions  
9 addressed by other Company witnesses regarding incentive compensation. Essentially,  
10 Mr. Wathen takes the same position as Mr. Carlin and Ms. Ahern, that is, paying  
11 incentives is standard practice for utilities. He also opines that PSO's incentive plan is in  
12 line with the incentive plans of other utility companies.<sup>44</sup> He further states that PSO's  
13 incentive plan design places a greater weighting (90% in total) on operational measures  
14 than financial measures (only 10%).  
15

16 **Q: DOES MR. WATHEN'S TESTIMONY HELP JUSTIFY THE COMPANY'S**  
17 **REQUEST TO RECOVER ITS INCENTIVE COMPENSATION COSTS**  
18 **THROUGH RATES?**

19 A: No. Mr. Wathen's testimony is essentially the same type of testimony filed by utility  
20 witnesses in every state where incentives are disallowed. His assurances that the  
21 Company's incentive plan is comparable to that of other utilities misses the point. It does  
22 not really matter that other utilities are making these payments; what matters is that other

1 utilities are not allowed to fully recover these costs in rates because the plans ultimately  
2 benefit the shareholders more than they do the customers.

3 Mr. Wathen's testimony that PSO's annual incentive plan is weighted 90% on  
4 operational measures and only 10% on financial measures is misleading for two  
5 important reasons. First, the testimony is about the performance metrics at PSO, not the  
6 metrics at AEP where the majority of the incentives payments are made (and passed on  
7 to PSO). Secondly, Mr. Wathen's testimony is about the performance metrics in the  
8 PSO plan, but gives no weighting or effect to the overriding funding mechanism that ties  
9 the amount of plan payments made each year (for these performance metrics) to the  
10 overall financial performance of AEP.

11  
12 **Q: HAVE YOU REVIEWED MR. CARLIN'S TESTIMONY THAT THIS**  
13 **COMMISSION HAS PREVIOUSLY ALLOWED RECOVERY OF INCENTIVE**  
14 **COMPENSATION?**

15 A: Yes. At page 21 of his direct testimony, Mr. Carlin cites two prior cases in which this  
16 Commission has allowed a utility's short-term annual incentives in rates, an Oklahoma  
17 Natural Gas ("ONG") case, PUD 201500213, and a Centerpoint Gas case, PUD  
18 201500118. Unfortunately, the ONG case was a settled case, and should not have been  
19 cited as precedent. More importantly, both cases Mr. Carlin cites are distinguishable  
20 because they involve gas utilities with Performance Based Ratemaking ("PBR")  
21 mechanisms, in which ratepayers have an opportunity to share in the increased earnings  
22 of the utility. The theory for allowing financial-based incentives for PBR utilities is that

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<sup>44</sup> Wathen Direct Testimony, page 6, lines 16-18.

1 ratepayers potentially could receive at least some of the benefits the incentives help  
2 produce. Without debating the merits of this theory, suffice it to say that PBR utilities  
3 are treated very differently for rate setting purposes in Oklahoma including the treatment  
4 of incentive compensation.

5  
6 **Q: DID YOU TAKE INTO ACCOUNT PSO'S ADJUSTMENT TO REDUCE TEST  
7 YEAR INCENTIVE PLAN EXPENSE TO TARGETED LEVELS?**

8 A: Yes. PSO's adjustment to reduce test year expense to targeted levels is a typical  
9 normalization adjustment that has to be made before any disallowances can be  
10 calculated. In other words, any disallowance of incentive compensation should be made  
11 to the normal, on-going level of incentive expense. Therefore, I accepted the Company's  
12 *targeted* levels for incentive payments and made my adjustments for financial-  
13 performance measures to the lower targeted levels rather than to the higher actual test  
14 year levels.

15  
16 **Q: WHAT IS THE LEVEL OF INCENTIVE PAYMENTS INCLUDED IN PSO'S  
17 PRO FORMA EXPENSE IN THIS APPLICATION?**

18 A: According to PSO's responses to AG 3-21\_ Att 1 and AG 3-21\_ Att 2, PSO included  
19 \$9,098,879 in pro forma operating expense for its annual incentive plans for all  
20 employees.

1

2 **Q: HOW IS THE OIEC's ADJUSTMENT CALCULATED?**

3 A: OIEC's adjustment to operating expense for regular incentives is set forth below and can  
4 be seen at *Exhibit MG-2.4*.

5	Annual Incentive Plan Payments in Pro Forma Expense	\$9,098,879
6	Percentage Associated with Company Financial Goals	<u>75%</u>
7	OIEC's Adjustment to Annual Incentive Plans	<u>\$ 6,824,159</u>

8

9 **Q: HAVE YOU PROPOSED ANY OTHER ADJUSTMENTS WITH RESPECT TO THE**  
10 **COMPANY'S ANNUAL INCENTIVE COSTS?**

11 A: Yes. I made an adjustment to remove from pro forma expense the Company's labor  
12 attendant costs associated with the 75% disallowance of short term incentives. This  
13 adjustment is set forth below and can be seen at *Exhibit MG-2.4*.

14	<b>OIEC Adjustment to Remove Labor Attendant Costs</b>	<u>\$ 756,117</u>
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15 **III. B. LONG-TERM EXECUTIVE STOCK INCENTIVE PLAN**

16 **Q: WHAT HAS PSO PROPOSED WITH RESPECT TO THE RECOVERY OF**  
17 **LONG-TERM STOCK INCENTIVE PLAN FOR EXECUTIVES?**

18 A: The Company is proposing to recover \$3,106,766<sup>45</sup> for its long-term incentive plan,  
19 which is the amount in pro forma operating expense after PSO's adjustment to increase  
20 test year expense to *targeted* levels for long-term incentives.

<sup>45</sup> See Exhibit MG 2-5.

1 **Q: WHAT TYPES OF INCENTIVES ARE PROVIDED TO SENIOR**  
2 **MANAGEMENT AT AEP AND PSO?**

3 A: In addition to the company-wide incentive plans discussed above, executives and  
4 managers of the Company are provided additional incentive compensation through  
5 AEP's Long-Term Incentive Plan.<sup>46</sup> This plan provides grants and awards in the form of  
6 *performance units* and *restricted stock units* (RSUs), both of which are generally similar  
7 in value to shares of AEP common stock.<sup>47</sup> The performance units are granted based on  
8 two equally weighted performance measures: three-year total shareholder returns, and  
9 three-year cumulative EPS relative to a Board-approved target.<sup>48</sup> As such, the Long-  
10 Term Incentive Plan is designed to align the interest of AEP's management with the  
11 interest of shareholders and to promote the financial success and growth of AEP.

12  
13 **Q: DO YOU RECOMMEND THE INCLUSION OF THE LONG-TERM**  
14 **INCENTIVE EXPENSE IN RATES?**

15 A: No. Incentive compensation payments to officers, executives and key employees of a  
16 utility are generally excluded for ratemaking purposes, and I agree with this treatment.  
17 Officers of any corporation have a legal, fiduciary duty to put the interests of the  
18 corporation first. This means that these individuals are required to put the interests of the  
19 company above the interest of the customers. Undoubtedly, the interests of the company  
20 and the interests of the customer are not always the same, and at times, can be quite

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<sup>46</sup> See Carlin Direct Testimony, page 18.

<sup>47</sup> See Carlin Direct Testimony, page 19, lines 1-6.

<sup>48</sup> See Carlin Direct Testimony, page 19, lines 6-10.

1 divergent. This natural divergence of interests creates a situation where not every cost  
2 associated with executive compensation is presumed to be a necessary cost of providing  
3 utility service. Many regulators are inclined to exclude executive bonuses, incentive  
4 compensation and supplemental benefits from utility rates, understanding that these costs  
5 would be better borne by the utility shareholders.

6 It has been my experience that some utilities treat long-term executive incentive  
7 compensation costs as a below-the-line item even without a Commission order directing  
8 them to do so. Further, long-term executive incentive plans are specifically designed to  
9 tie executive compensation to the financial performance of the company. This is done to  
10 further align the interest of the employee with those of the shareholder. Since the  
11 compensation of the employee is tied over a long period of time to the company's stock  
12 price, it motivates employees to make business decisions from the perspective of long-  
13 term shareholders. This intentional alignment of employee and shareholder interests  
14 means the costs of these plans should be borne solely by the shareholders. It would be  
15 inappropriate to require ratepayers to bear the costs of incentive plans designed to  
16 encourage employees to put the interest of the shareholders first.

17  
18 **Q: HOW IS LONG-TERM INCENTIVE COMPENSATION TREATED IN OTHER**  
19 **STATES?**

20 **A:** The results of the Garrett Group Incentive Survey, discussed in the previous section of  
21 this testimony, show that most states follow the general rule that incentive pay associated  
22 with financial performance is not allowed in rates. This means that long-term, stock-

1 based incentives are not allowed in virtually every state. In the synopsis of the incentive  
2 survey results from each state that was included in the prior section of this testimony, the  
3 treatment of long-term stock based incentives in each state is underlined. According to  
4 the survey, 20 of the 24 western states tend to exclude all or virtually all long-term stock-  
5 based incentive pay, either through an outright ban on stock-based incentives or through  
6 applying the *financial performance* rule, which has the effect of excluding long-term  
7 earnings-based and stock-based awards. These states include Arizona, Arkansas,  
8 California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada,  
9 New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah,  
10 Washington and Wyoming. In the other four states, Alaska, Iowa, Montana and  
11 Nebraska, the issue has not been addressed.

12  
13 **Q: IS YOUR RECOMMENDED TREATMENT TO EXCLUDE LONG-TERM**  
14 **INCENTIVE COMPENSATION TO SENIOR MANAGEMENT CONSISTENT**  
15 **WITH THE TREATMENT GENERALLY PRESCRIBED IN OTHER STATES?**

16 A: Yes. In our survey of incentive compensation treatment in other states, we found that  
17 virtually all commissions exclude executive stock-based compensation, such as AEP's  
18 Long-Term Incentive Plan.

19  
20 **Q: IS YOUR RECOMMENDATION ALSO CONSISTENT WITH THE**  
21 **TREATMENT OF LONG-TERM INCENTIVES IN OKLAHOMA?**

1 A: Yes. In Oklahoma, the Commission has a long and consistent history of excluding long-  
2 term, stock-based incentives. For example, in PSO's last three litigated rate cases, 100%  
3 of the costs of the long-term incentive plans were excluded.<sup>49</sup>

4  
5 **Q: WHEN UTILITIES INCLUDE LONG-TERM INCENTIVE COMPENSATION IN**  
6 **RATES, WHAT RATIONALE IS GENERALLY PROVIDED?**

7 A: Generally, utilities argue that executive incentives are part of an overall compensation  
8 package that is designed to attract and retain qualified personnel. Since other utilities  
9 offer incentive plans to their executives, a company would run the risk of not being able  
10 to compete for key personnel if it did not offer a comparable plan.<sup>50</sup>

11  
12 **Q: IS THE COMPANY'S ARGUMENT PLAUSIBLE?**

13 A: No. The problem with the Company's "total compensation package" argument is that  
14 when an incentive payment is based on achieving financial performance goals there  
15 should be a financial benefit to the company that comes from achieving these goals.  
16 This financial benefit should provide ample additional funds from which to make the  
17 incentive payments. If not, the plan was poorly conceived. Thus, a utility is not placed  
18 at a competitive disadvantage when incentive payments tied to financial performance are  
19 not collected through rates, because the funding for these payments should come out of  
20 the additional earnings the incentive plans help achieve.

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<sup>49</sup> Cause Nos. PUD 200600285, PUD 200800144 and PUD 201500208.

<sup>50</sup> See for example, Direct Testimony of Andrew Carlin, page 20, lines 7-10.

1 Further, when utilities, such as AEP/PSO, compete with other utilities for  
2 qualified executives, and the executive incentive compensation plans of those other  
3 utilities are not being recovered through rates, AEP/PSO is not placed in a competitive  
4 disadvantage when its executive incentive compensation is excluded as well. Since most  
5 states exclude executive incentive pay as a matter of course and most other states  
6 exclude executive incentives as a practical matter, AEP/PSO would actually be given an  
7 unfair advantage if its executive plans were included in rates. The fact that other  
8 utilities offer executive incentive plans is not relevant; what is relevant is the fact that  
9 other utilities are not recovering the costs of these plans in rates. In an order disallowing  
10 Nevada Power's long-term incentive plan, the Nevada Commission articulated this  
11 important ratemaking concept as follows:

12 Therefore, the Commission accepts BCP's and SNHG's  
13 recommendations to disallow recovery of expenses associated with  
14 LTIP. Both parties provide a valid argument that this type of  
15 incentive plan is mainly for the benefit of shareholders. Further,  
16 both BCP and SNHG provide examples of numerous other  
17 jurisdictions that do not allow the recovery of these costs and,  
18 therefore, disallowance in this instance would not place NPC in a  
19 competitive disadvantage.<sup>51</sup> (Emphasis added).

20 **Q: PLEASE DESCRIBE YOUR ADJUSTMENT TO THE COMPANY'S LONG-**  
21 **TERM STOCK INCENTIVE PLAN FOR SENIOR MANAGEMENT.**

22 **A:** I recommend that all of the cost of AEP's Long-Term Incentive Plan be excluded from  
23 rates. OIEC's adjustment removes 100% of the cost of the plan included in pro forma  
24 operating expense in the amount of \$3,106,766. The calculations supporting this  
25 adjustment are set forth at *Exhibit MG-2.4*.

1 **OIEC Adjustment to Exclude 100% of Long-Term Incentives \$ 3,106,766.**

2 **III. C. SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN (“SERP”)**

3 **Q: PLEASE DESCRIBE THE SUPPLEMENTAL EXECUTIVE PENSION PLAN.**

4 A: The Company provides supplemental retirement benefits to officers, and division presidents  
5 of the Company. Supplemental retirement plans for highly compensated individuals are  
6 provided because benefits under the general pension plans are subject to certain limitations  
7 under the Internal Revenue Code. Benefits payable under these supplemental plans are  
8 typically equivalent to the amounts that would have been paid but for the limitations  
9 imposed by the Code. In general, the limitations imposed by the Code allow for the  
10 computation of benefits on annual compensation levels of up to \$265,000 for 2015 and  
11 \$270,000 for 2016. Retirement benefits on compensation levels in excess of annual  
12 compensation limits are paid through supplemental plans. Supplemental retirement plans  
13 for highly compensated employees are designed to provide benefits in addition to the  
14 benefits provided under the general pension plans of the company.

15 **Q: WHAT AMOUNTS WERE INCLUDED IN PRO FORMA OPERATING EXPENSE**  
16 **FOR THE SUPPLEMENTAL EXECUTIVE PENSION PLAN?**

17 A: The amount of SERP costs included in PSO’s filed cost-of-service was \$349,862, which is  
18 comprised of \$96,780 for PSO and \$253,082 for AEPSC.<sup>52</sup>

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<sup>51</sup> See Final Order in Docket 08-12002 at paragraph 549.

<sup>52</sup> See Exhibit MG-2.5.

1 **Q: WHAT DO YOU RECOMMEND WITH RESPECT TO SUPPLEMENTAL**  
2 **EXECUTIVE RETIREMENT COSTS?**

3 A: Yes. I recommend a sharing of the total executive benefits costs as follows: I  
4 recommend that ratepayers pay for all of the executive benefits included in the  
5 Company's regular pension plans, and that shareholders pay for the additional executive  
6 benefits included in the supplemental plan. For ratemaking purposes, shareholders  
7 should bear the additional costs associated with supplemental benefits to highly  
8 compensated executives, since these costs are not necessary for the provision of utility  
9 service, but are instead discretionary costs of the shareholders designed to attract, retain  
10 and reward highly compensated employees. Further, because officers of any corporation  
11 have a fiduciary duty to put the interests of the corporation first, these individuals are  
12 required to put the interest of the company above the interests of the customers. This  
13 creates a situation where not every cost associated with executive compensation is  
14 presumed to be a cost appropriately passed on to ratepayers. Many regulators are  
15 inclined to exclude executive bonuses, incentive compensation and supplemental  
16 benefits from utility rates, understanding that these costs would be better borne by the  
17 utility shareholders.<sup>53</sup>

18  
19 **Q: HAS THIS COMMISSION ORDERED A DISALLOWANCE OF SERP**  
20 **EXPENSE IN PRIOR CASES?**

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<sup>53</sup> For example, this Commission excluded SERP costs in PSO's last two litigated rate case, PUD 06-285 and PUD 08-144.

1 Yes. The Commission disallowed 100% of AEP/PSO's SERP expense in PSO's 2006  
2 rate case, Cause No. PUD 200600285. Specifically, the Commission stated:

3 q. **Employee Benefits-Supplemental Executive Retirement**  
4 **Plan ("SERP").**  
5

6 PSO included \$596,081 as Supplemental Executive Retirement  
7 Plan ("SERP") in its cost-of-service. The Commission adopts  
8 OIEC's proposal to remove the SERP Expense from the revenue  
9 requirement in this proceeding. The Commission adopts OIEC's  
10 recommendation that ratepayers pay for all of the executive  
11 benefits included in PSO's regular pension plans and that  
12 shareholders pay for the additional executive benefits included in  
13 the supplemental plan.

14 Again, in PSO's 2008-rate case, Cause No. PUD 200800144, the Commission disallowed  
15 100% of the Company's SERP expense.

16 **11. Supplemental Executive Retirement Plan ("SERP").**  
17

18 The AG and OIEC recommend reductions to reflect the  
19 elimination of SERP expense from PSO's cost of service. Staff  
20 proposed no adjustment to PSO's recommendation. SERP is  
21 AEP's non-qualified defined benefit retirement plan that PSO  
22 argued allows AEP the flexibility to attract and retain key  
23 employees and provides benefits that cannot be provided under  
24 AEP's qualified defined benefit plans. PSO stated that the  
25 combined plans, of which SERP is a part, allow employees to  
26 accumulate an appropriate level of replacement income upon  
27 retirement. According to PSO, SERP plans and other benefits are  
28 part of a market competitive benefits program for the utility  
29 industry and large employers in general. The Commission finds  
30 that the SERP expenses do not provide a benefit to the ratepayers  
31 of PSO and therefore adopts the recommendation of the AG and  
32 OIEC to deny recovery of these costs from PSO's ratepayers.

33 Again, in PSO's 2015 rate case, Cause No. PUD 201500208, the Commission disallowed  
34 100% of the Company's SERP expense.

1 The ALJ finds that it has consistently disallowed PSO's SERP  
2 costs in the past. The Commission disallowed 100% of PSO's  
3 SERP expense in PS O's 2006 rate case, Cause No. PUD  
4 200600285, and in PSO's 2008 rate case, Cause No. PUD  
5 200800144, the Commission again disallowed 100% of the  
6 Company's SERP expense.

7 The ALI finds that SERP expenses are disallowed in other  
8 jurisdictions. (*See* Garrett Responsive Testimony, pp. 43-44). The  
9 Commission further finds that for rate-making purposes, utility  
10 shareholders should bear the additional costs associated with  
11 supplemental benefits to compensated executives. Therefore, the  
12 ALJ finds that the SERP expenses in the amount of \$468,192,  
13 which is \$156,433 of SERP costs at PSO and \$311,759 of SERP  
14 costs at AEPSC, do not provide a benefit to PSO ratepayers, and  
15 therefore, PSO should be denied recovery of these costs in  
16 accordance with the recommendations of the AG and OIEC. (*See*  
17 Hearing Ex. 62).

18 **Q: HOW IS SERP EXPENSE TREATED IN OTHER JURISDICTIONS WHERE**  
19 **YOU HAVE TESTIFIED ON THIS ISSUE?**

20 A: In my experience, SERP expenses are consistently disallowed. For example, in Nevada,  
21 the Commission has disallowed SERP expense in Docket Nos. 01-10001, 03-10001, 06-  
22 11022, 08-12002, and 11-06006. In Arkansas, in Entergy Arkansas, Inc's last rate case  
23 (Docket No. 13-028-U), the Arkansas Public Service Commission agreed with my  
24 testimony in that Docket (on behalf of the Hospital and Higher Education Group), that  
25 the shareholders, not ratepayers, should pay for the cost of Entergy Arkansas'  
26 Supplemental Executive Retirement Plans. In the Commission's Order No. 21 entered in  
27 this Docket, the Arkansas Commission determined that SERP expenses are not necessary  
28 to provide utility service, but rather are discretionary costs implemented by Entergy

1 Arkansas and therefore should be disallowed. In Texas, in Entergy's last rate case,  
2 Docket No. 39896, the Texas PUC disallowed all of the Company's SERP costs.

3 140. ETI provides non-qualified supplemental executive  
4 retirement plans for highly compensated individuals such as key  
5 managerial employees and executives that, because of limitations  
6 imposed under the Internal Revenue Code, would otherwise not  
7 receive retirement benefits on their annual compensation over  
8 \$245,000 per year.

9 141. ETI's non-qualified supplemental executive retirement  
10 plans are discretionary costs designed to attract, retain, and reward  
11 highly compensated employees whose interests are more closely  
12 aligned with those of the shareholders than the customers.

13 142. ETI's non-qualified executive retirement benefits in the  
14 amount of \$2,114,931 are not reasonable or necessary to provide  
15 utility service to the public, not in the public interest, and should  
16 not be included in ETI's cost of service.

17 **Q: ARE YOU AWARE OF OTHER JURISDICTIONS IN WHICH SERP EXPENSE**  
18 **IS DISALLOWED?**

19 **A:** I have not conducted a comprehensive study of SERP treatment in other states, but I do  
20 know that SERP is disallowed in the states of Oregon,<sup>54</sup> Idaho,<sup>55</sup> and Arizona.<sup>56</sup>

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<sup>54</sup> See Oregon Public Utilities Commission, Order No. 01-787, September 7, 2001, page 44.

The Commission has not allowed recovery of SERP expenses in other utility rate cases. PacifiCorp has not persuaded us that it is necessary to pay SERP to hire and retain executive officers. The SERP costs are not allowed."

<sup>55</sup> See Idaho Public Utilities Commission Order No. 32196 issued February 28, 2011 in Rocky Mountain Power's rate case, Case No. Pac-E-10-07:

The Commission finds Staff's argument persuasive and finds it reasonable to disallow Company recovery of SERP costs of \$2.6 million (total Company) in this case. The Company has not demonstrated that the costs are related to providing services to southeast Idaho. The responsibility for generous severance benefits for executives, we find, is the responsibility of the Company and its shareholders, not Idaho customers.

<sup>56</sup> The Arizona Corporation Commission has issued several decisions in which it denied rate recovery for SERP expenses. See 258 PUR 4th 353 (2007) *Re Arizona Public Service Company*, 247 PUR 4th 243 (2006); *In Re Southwest Gas Corp.*, 2008 WL 2332953 (Arizona Corp Comm'n. Decision 70360, May

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**Q: WHAT ADJUSTMENT ARE YOU RECOMMENDING?**

A: This adjustment is set forth below and the calculations supporting the adjustment can be seen at *Exhibit MG2.5*.

**OIEC Adjustment to Remove SERP Expense** **\$349,862**

**III. D. RATE CASE EXPENSE**

**Q: WHAT IS THE AMOUNT THE COMPANY SEEKS TO RECOVER FOR RATE CASE EXPENSE IN THIS CAUSE?**

A: The Company seeks to recover \$1,161,066 of estimated rate case costs in this case amortized over a two year period, for an increase in rates of \$580,533 per year. The total rate case costs requested represents a 57% increase over the Company's \$740,000 estimated costs requested for the 2013 rate case. Notably, the estimated outside legal fees more than doubled from \$200,000 in Cause No. PUD 201300217, to \$500,000 in the current case.

**Q: DO YOU AGREE WITH THE ESTIMATED RATE CASE COSTS THAT THE COMPANY SEEKS TO RECOVER?**

No. In my view, the Company's rate case cost estimates are significantly overstated. As noted above, a 150% increase from \$200,000 to \$500,000 for outside legal fees appears excessive. In addition, the Company's estimate of \$150,000 for a Return on Equity

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27, 2008); *In the Matter of the Application of UNS Electric*, 2007 WL 4731250 (Arizona Corp Comm'n Decision 70011, November 27, 2007).

1 ("ROE") witness is far above market. In my experience, the rate for an ROE witness is  
2 between \$25,000 and \$50,000, with utility companies typically paying the higher end of  
3 the scale. The Company has also added a cumulative rate of return witness at \$100,000  
4 that should be paid by shareholders. Further, the Company seeks to include \$107,000 for  
5 a demolition study witness that has appeared now in three rate cases supporting the same  
6 demolition study. Finally, the Company seeks \$43,500 for notice costs when those costs  
7 have been \$5,000 in the past two rate cases. In my opinion, rate case expense costs  
8 should be scrutinized as not all rate case costs should be borne by ratepayers. Only  
9 necessary and reasonable costs to process a rate case should be borne by ratepayers and  
10 these necessary costs should be evaluated using a *least-cost* standard. Ratepayers should  
11 not be burdened with unreasonable rate case costs, especially when the testimony  
12 appears to be self-serving shareholder testimony.

13 **Q: WHAT ADJUSTMENT ARE YOU RECOMMENDING?**

14 A: I recommend that the Company's total recovery of rate case expense be reduced from  
15 \$1,161,066 to \$590,566. This is a more reasonable expense level based on current  
16 market rates, and is also closer to the actual expenses incurred in the Company's 2013  
17 rate case. I also recommend that rate case costs be recovered over a 4-year rather than a  
18 2-year period. The longer recovery period reduces costs now and protects against the  
19 risk of over-recovery by the utility if the Company does not file its next rate case in two  
20 years. Any unrecovered amounts at the Company's next rate case can be included as a  
21 deferred asset for further recovery at that time. A 4-year amortization results in an

1 adjustment to PSO's requested rate case expense of \$432,892. The calculations  
2 supporting this recommendation can be seen at *Exhibit MG2.6*.

3 **OIEC adjustment to estimated pro forma Rate Case Expense (\$432,892)**  
4

5 **III. E. STORM DAMAGE EXPENSE**

6 **Q: WHAT IS THE COMPANY PROPOSING FOR STORM DAMAGE EXPENSE?**

7 A: The Company is proposing increase test year storm damage expense by \$8.264 million,  
8 from \$2.936 million to \$11.200 million.<sup>57</sup> The reason for the proposed adjustment is that  
9 the Company has been experiencing an increase in storm damage expense over the past  
10 several years. The Company wants to increase test year expense to the 7-year average  
11 storm damage experienced from 2010 through 2016, which was about \$11.2 million.  
12 Even though the Company is allowed to recover excess storm damage expense –  
13 meaning storm damage expense greater than the amount embedded in base rates –  
14 through a tracker mechanism, the Company still wants to increase the amount included  
15 in base rates to a much higher level, so that amounts recovered through the tracker  
16 mechanism can be lower.

17  
18 **Q: DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT?**

19 A: No. Since the Company is insulated from under-recovery through the tracker  
20 mechanism, there is no need to increase base rates now based on anticipated increases in  
21 storm damage expense in the future. In my opinion, the Commission should leave test  
22 year expense level where it is, and should continue to allow PSO to recover its excess

1 storm expense through the approved tracker mechanism. The calculations supporting this  
2 recommendation can be seen at *Exhibit MG2.8*.

3 **OIEC adjustment to reverse PSO's Storm Damage Adjustment** **(\$8,263,753)**

### III. F. PAYROLL EXPENSE

4 **Q: PLEASE DESCRIBE PSO'S PROPOSED PAYROLL ADJUSTMENT.**

5 A: PSO's proposed payroll adjustment is a two-part adjustment. The first part annualizes  
6 payroll expense at test year end by multiplying the final pay period in December 2016 by  
7 the number of pay periods in the year. This amount is then increased by a projected  
8 3.5% pay raise in 2017. The Company's adjustment increases the test year payroll  
9 expense from \$52,562,165 to \$55,289,240, or by \$2,727,075,<sup>58</sup> which is an astonishing  
10 5.2% requested increase in payroll cost.

11 **Q: DO YOU AGREE WITH THE COMPANY'S APPROACH?**

12 A: No. Regarding the first part of the adjustment, an annualization that multiplies a final  
13 pay period by 12 or 26 is only appropriate if the final pay period is representative of  
14 ongoing levels. Regarding the second part of the adjustment, an additional increase for  
15 pay raises based on the nominal amount of the pay raises is almost never appropriate  
16 because payroll levels almost never increase by the nominal amount of the pay raise. In  
17 other words, a 3.5% pay raise will almost never result in a 3.5% increase in payroll  
18 expense levels. The actual increase amount associated with a nominal pay raise is not  
19 known and measurable because too many other factors impact the overall change in

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<sup>57</sup> See Direct Testimony of R. Hamlett at page 8.

<sup>58</sup> See WP H2-1.

1 payroll expense. These factors include: (1) the normal turnover of employees in a  
2 company the size of PSO, where employees come onto and leave the payroll registers on  
3 a regular basis, with retiring employees taking higher salaries levels off the system and  
4 new employees coming on at lower pay scale levels; (2) workforce reorganizations,  
5 where significant reductions in the workforce levels are achieved through new  
6 technologies or other innovations; (3) productivity gains, where smaller reductions in the  
7 workforce levels are achieved on an ongoing basis through increased employee  
8 efficiencies; and (4) capitalization ratio changes, where more payroll costs are  
9 capitalized (rather than expensed) during a period of capital expansion – such as many  
10 utilities are experiencing now. All of these factors impact overall payroll cost levels as  
11 much or more than pay raises do. Yet, regulated utilities, in their rate cases, often want  
12 to only acknowledge the pay raise impacts while ignoring the impacts of these other  
13 important changes that often lower overall expense levels.

14  
15 **Q: DO YOU HAVE A GOOD EXAMPLE OF PAYROLL COSTS NOT**  
16 **INCREASING BY THE AMOUNT OF A PAY RAISE?**

17 **A:** Yes. PSO's last rate case provides a perfect example. In that case, PSO requested a  
18 3.85% increase in payroll costs from \$53.096 million in the test year to \$55.134 million,  
19 based again on post-test year pay raises. However, actual payroll costs went down by  
20 1.01%, not up by 3.85% as the Company predicted. Actual payroll costs went from  
21 \$53.096 million in the test year, which ended January 31, 2015, to \$52.562 million for  
22 the 12-month period ending December 31, 2016.

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**Q: WHAT IS THE APPROPRIATE LEVEL TO INCLUDE IN RATES?**

A: The appropriate level for any operating expense is the test year level unless it can be shown that the test year level is not representative of the level that will be in effect during the rate-effective period. In PSO's case, new rates from the Company's last rate case went into effect in January 2017. This means that the reasonable level of payroll costs *ordered by the Commission* went into effect just eight months ago. Not even one year has passed since the Commission established this level. In my opinion, it is too early to set a new level for payroll costs. The Company's payroll adjustment methodology is unreliable, and not enough time has passed to tell whether or not the level established by the Commission in January of this year is sufficient.

**Q: WHAT ADJUSTMENTS ARE YOU RECOMMENDING?**

A: My adjustments reverse the adjustments recommended by the Company for both PSO and AEPSC allocated costs. The adjustments are set forth below and can be seen at *Exhibit MG-2.3*.

Reverse PSO requested increase in PSO payroll costs	\$(2,726,115)
Reverse PSO requested increase in AEPSC payroll costs	\$(2,773,667)

1           **III. G. PRODUCTION OPERATIONS AND MAINTENANCE EXPENSE**

2   **Q.    WHAT LEVEL OF PRODUCTION OPERATIONS AND MAINTENANCE**  
3   **(O&M) EXPENSE DID PSO INCUR DURING THE TEST YEAR?**

4   A.    PSO incurred \$78.87 million for non-fuel production O&M expense during the test year  
5   ending December 31, 2016.<sup>59</sup>

6  
7   **Q.    WHAT AMOUNT IS PSO REQUESTING FOR NON-FUEL PRODUCTION**  
8   **O&M IN THIS CASE?**

9   A.    PSO is requesting that it be allowed to recover approximately \$80.25 million for non-  
10   fuel O&M through its new rates.<sup>60</sup>

11  
12   **Q.    WHAT ADJUSTMENTS TO THE ACTUAL TEST YEAR PRODUCTION O&M**  
13   **EXPENSE IS PSO PROPOSING?**

14   A.    PSO is proposing three adjustments to test year production O&M. First, the Company  
15   proposes to reduce its test year O&M by \$293,664 to reflect the expense reductions  
16   resulting from the retirement of its Northeastern Unit 4 coal unit in April of 2016.<sup>61</sup>  
17   Secondly, PSO proposes to increase its test year O&M by \$300,000 to account for  
18   increased expenses that it expects to incur for new environmental control systems that  
19   were installed at Northeastern Unit 3 and the Comanche Power Station units.<sup>62</sup> The final  
20   adjustment proposed by PSO is a \$2.11 million increase in expense to reflect what the

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<sup>59</sup> See Table 3 on page 11 of PSO Witness Slater's Direct Testimony.

<sup>60</sup> See Table 3 on page 11 of PSO Witness Slater's Direct Testimony.

<sup>61</sup> See page 10 of PSO Witness Slater's direct testimony.

1 Company claims was an abnormally low level of O&M expense during the test year.<sup>63</sup>

2  
3 **Q. IS THE AMOUNT REQUESTED BY PSO FOR PRODUCTION O&M**  
4 **REASONABLE?**

5 A. No. PSO's proposed production O&M adjustments are unreasonable and would result in  
6 the Company collecting an excessive level of O&M expenses through its base rates. For  
7 example, PSO's proposed \$293,664 test year adjustment for retirement of Northeastern  
8 Unit 4 greatly understates the reduction in expenses that should reasonably result from  
9 retirement of the unit. As indicated in Table 3 below, the combined O&M for  
10 Northeastern Units 3 and 4 averaged approximately \$26.4 million per year over the  
11 2012-2015 period, while the Test Year expense level was approximately 90% of this  
12 amount before PSO's adjustment and 89% of the average historical level of expense with  
13 the Company's proposed adjustment. It simply makes no sense that the cost to operate,  
14 maintain and staff one coal unit would only be approximately 10% lower than the O&M  
15 cost for two coal units, as PSO's adjustment suggests.

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<sup>62</sup> See page 10 of PSO Witness Slater's direct testimony.

<sup>63</sup> See pages 10-11 of PSO Witness Slater's direct testimony.

**Table 3: Comparison of Combined O&M for Northeastern Units 3 and 4**

<u>FERC Accoun</u>	<u>Description</u>	<u>2013-15 Avg</u>	<u>2016 TY</u>	<u>% of Avg</u>
5000	Operation Supervision and Engineering	\$5,466,850	\$4,865,098	89%
5020	Steam Expenses	\$1,254,733	\$797,997	64%
5050	Electric Expenses	\$1,771,534	\$61,509	3%
5060	Miscellaneous Steam Power Expenses	\$2,575,945	\$3,193,505	124%
5070	Rents	\$6,761	\$13,891	205%
5100	Maintenance Supervision and Engineering	\$1,375,647	\$1,463,700	106%
5110	Maintenance of Structures	\$597,149	\$414,927	69%
5120	Maintenance of Boiler Plant	\$10,355,125	\$8,181,609	79%
5130	Maintenance of Electric Plant	\$2,537,144	\$2,564,732	101%
5140	Maintenance of Miscellaneous Steam Plant	<u>\$489,340</u>	<u>\$2,357,662</u>	<u>482%</u>
	Total O&M	\$26,430,228	\$23,914,630	90%
	NE4 Retire Adjustment:		<u>-\$293,664</u>	
	PSO Proposed		\$23,620,966	89%

1 **Q. WHAT IS YOUR RECOMMENDED ADJUSTMENT FOR RETIREMENT OF**  
2 **NORTHEASTERN UNIT 4?**

3 A. I recommend that PSO's test year O&M be reduced by \$5.68 million based on adjusting  
4 the 2013-15 average O&M expense incurred for Northeastern Units 3 & 4 downward to  
5 a level of \$17.94 million, which reflects 80% of O&M supervision and engineering  
6 accounts (500 and 510), 60% of Boiler and Electric Maintenance accounts (512 and  
7 513), and 70% of all other O&M accounts. This results in an allowed O&M level for  
8 Northeastern Unit 3 that is 68% of the level incurred before Northeastern Unit 4 was  
9 retired.<sup>64</sup>

10  
11 **Q. IS PSO'S PROPOSED \$300,000 ADJUSTMENT TO TEST YEAR O&M**  
12 **EXPENSES FOR INCREASED ENVIRONMENTAL O&M EXPENSES**  
13 **REASONABLE?**

1 A. No. The Company's proposed adjustment for increased environmental O&M expenses  
2 associated with new environmental control equipment at the Northeastern and Comanche  
3 generating stations constitutes improper piecemeal ratemaking. Moreover, the proposed  
4 \$300,000 adjustment for this issue is only slightly more than 1% of PSO's total test year  
5 production O&M expense. It is not appropriate to single out one specific type of  
6 expense that is increasing, particularly at such a small level, while ignoring other types  
7 of production O&M activities which are decreasing by a similar, or even greater,  
8 amount.

9  
10 **Q. IS PSO'S PROPOSED \$2.11 MILLION INCREASE TO NORMALIZE TEST**  
11 **YEAR PRODUCTION O&M EXPENSES REASONABLE?**

12 A. No. The Company claims that this normalization adjustment was necessary to account  
13 for an abnormally low level of test year expenses associated with major maintenance  
14 activities.<sup>65</sup> PSO indicates that this adjustment was based on averaging O&M expenses  
15 for the test year plus the two prior years expenses, excluding Northeastern Unit 4 O&M  
16 expense.<sup>66</sup> This proposed adjustment is flawed in that it assumes that the three-year  
17 period used to determine "normal O&M levels" were in fact normal periods. The  
18 Company has not presented evidence to support this assumption. Moreover, during this  
19 period there were several major abnormal events that could have significantly impacted  
20 PSO maintenance expenses, including implementation of the SPP's new Integrated  
21 Market, the installation of new environmental controls to meet MATS requirements, and

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<sup>64</sup> See Exhibit SN-1.

<sup>65</sup> See page 11 of PSO Witness Slater's direct testimony.

1 the retirement of Northeastern Unit 4. For this reason, PSO's proposed \$2.11 million  
2 test year production O&M normalization adjustment should be rejected.

3  
4 **Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO PSO'S**  
5 **TEST YEAR PRODUCTION O&M**

6 A. I recommend that PSO's test year production O&M be reduced by \$5.68 million to  
7 properly reflect the retirement of Northeastern Unit 4.<sup>67</sup> I further recommend that PSO's  
8 proposed test year adjustments for environmental compliance costs and abnormal  
9 maintenance expenses be rejected.

10  
11 **Q. HAVE YOU IDENTIFIED OTHER POTENTIAL ISSUES THAT SHOULD BE**  
12 **CONSIDERED IN DECIDING THE APPROPRIATE LEVEL OF PRODUCTION**  
13 **O&M TO BE INCLUDED IN SETTING PSO'S NEW RATES?**

14 A. Yes. In the course of my review of PSO's test year production O&M expenses, I  
15 determined that the Company has reported a \$106.7 million credit to FERC Account  
16 557, Other Expense, during the test year period.<sup>68</sup> However, this credit is not addressed  
17 by PSO's testimony and is not reflected in the Company's schedules for production  
18 O&M expense. Therefore, I am unable to clarify the nature of this credit or why it was  
19 not addressed or reflected in PSO's testimony.

20  
21 **Q. WHAT IS YOUR CONCERN REGARDING THIS CREDIT?**

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66 See page 11 of PSO Witness Slater's direct testimony.

67 See Exhibit SN-1.

1 A. The Code of Federal Regulations defines FERC Account 557, Other Expense, broadly  
2 and to include insurance recoveries as follows:

3  
4 A. This account shall be charged with any production expenses including expenses  
5 incurred directly in connection with the purchase of electricity, which are not specifically  
6 provided for in other production expense accounts. Charges to this account shall be  
7 supported so that a description of each type of charge will be readily available.

8  
9 B. Recoveries from insurance companies, under use and occupancy provisions of  
10 policies, of amounts in reimbursement of excessive or added production costs for which  
11 the insurance company is liable under the terms of the policy shall be credited to this  
12 account.

13  
14 My concern is that this large credit may reflect amounts received by PSO to compensate  
15 for unreasonable costs due to equipment failures or other such issues, and that the  
16 Company is not properly refunding such credits to its customers under its proposed rates.

17  
18 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ISSUE?**

19 A. To the extent the \$106.7 million credit to FERC account 557 represents reimbursement  
20 or refund of costs that should be credited to PSO's customers, I recommend that this  
21 credit be refunded to customers, with interest, over a 3-year period as an offset to PSO's

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68 See Exhibit SN-2.

1 requested test year revenue requirement. This refund would be approximately \$35.56  
2 million per year, excluding related interest.

3  
4 **Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR O&M**  
5 **ADJUSTMENTS?**

6 A. My O&M adjustments reverse PSO's proposed production O&M adjustment in the  
7 amount of \$2,110,317, and reduce the test year O&M for Northeastern Unit 4 Production  
8 costs in the amount of \$5,680,000, for a total adjustment of \$7,790,317. These  
9 adjustments are set forth below and can be seen at *Exhibit MG-2.9*.

10  
11

Remove Generation O&M Costs	\$ (2,110,317)
Reduce Production O&M for Northeastern Unit 4 Production Costs	<u>\$ (5,680,000)</u>
Total OIEC adjustment to production O&M costs	<u>\$ (7,790,317)</u>

12  
13

**III. H. SOUTHWEST POWER POOL TRANSMISSION EXPENSES**

14 **Q. HOW DOES PSO RECOVER SOUTHWEST POWER POOL (SPP)**  
15 **TRANSMISSION EXPENSES?**

16 A. PSO recovers SPP transmission expenses through base rates and through the Company's  
17 SPP Transmission Cost (SPPTC) Tariff.

18  
19 **Q. WHAT LEVEL OF SPP TRANSMISSION EXPENSES HAS PSO INCURRED**  
20 **OVER THE LAST FIVE YEARS?**

1 A. As summarized in the table below,<sup>69</sup> PSO has incurred more than \$194 million in SPP  
 2 transmission expenses over the last four years (excluding Schedule 11 charges recovered  
 3 through the SPPTC Tariff), and there has been a significant increasing trend in these  
 4 expenses. The Company's SPP expenses totaled more than \$53.4 million during the test  
 5 year.

PUBLIC SERVICE COMPANY OF OKLAHOMA  
 SPP Charges to PSO by Schedule  
 For the years 2012 through 2016

SPP OATT Schedule	Calendar Years				Test Year	Requested
	2012	2013	2014	2015	2016	
Sch 1	4,206	5,265	19,532	94,977	(34,709)	(34,709)
Sch 1 Anc	154,974	115,567	149,070	157,752	214,029	214,029
Sch 1A Admin	7,102,880	8,826,686	10,083,555	10,987,276	10,144,864	11,537,415
Sch 2	132,640	136,738	148,455	16,869	(81,442)	(81,442)
Sch 8 Non-Firm Pt to Pt	26,528	437,160	100,225	78,353	(486)	(486)
Sch 9 NITS	13,070,526	21,303,306	26,416,586	27,304,311	34,498,256	48,492,881
Sch 11 (A)	649,466	1,065,928	2,301,843	4,564,592	7,449,504	9,591,763
Sch 12-FERC PtP	1,368,145	1,207,454	1,232,683	1,413,889	1,229,619	1,335,789
	22,509,364	33,098,105	40,451,949	44,618,018	53,419,635	71,055,240

(A) Schedule 11 charges reported for calendar years 2012 through 2016 have been reduced to remove costs recovered through the SPPTC tariff, consistent with the requested amount shown.

6 **Q. WHAT TYPES OF SPP EXPENSES DOES PSO RECOVER THROUGH BASE**  
 7 **RATES?**

8 A. PSO recovers all SPP expenses except for third party SPP Schedule 11 charges  
 9 (excluding OK Transco), which are recovered through the Company's SPPTC Tariff.

10

11 **Q. IS PSO PROPOSING ANY ADJUSTMENTS TO ITS TEST YEAR SPP**  
 12 **EXPENSES IN THIS CASE?**

<sup>69</sup> Source is PSO's original response to OIEC 14-5.

1 A. Yes. PSO's base rate SPP expenses during the test year totaled \$53.4 million. The  
2 Company is proposing a number of adjustments, primarily to annualize SPP charges  
3 which changed during the test year, and to remove expenses that are recovered through  
4 the SPPTC Tariff. The net impact of these proposed annualization adjustments would  
5 serve to increase the SPP expenses PSO recovered during the test year by \$17.64  
6 million, or approximately 33%.<sup>70</sup>

7

8 **Q. ARE THE ADJUSTMENTS TO SPP EXPENSES PROPOSED BY PSO**  
9 **REASONABLE?**

10 A. I was not able to reach any conclusions regarding the reasonableness of PSO's proposed  
11 adjustments to SPP test year expenses from the information provided in the Company's  
12 testimony and workpapers. For example, PSO witness Hamlett indicates that the support  
13 for the Company's proposed \$17.64 million increase in SPP expenses is provided by his  
14 testimony and the testimony of PSO witness Ross.<sup>71</sup> However, Mr. Hamlett only has one  
15 paragraph of testimony and a single workpaper page to support his assertion that PSO's  
16 proposed test year adjustments for SPP expenses are reasonable. Moreover, while PSO  
17 witness Ross discusses the general nature of SPP expenses incurred by PSO, and the  
18 Company's participation in SPP meetings, his testimony does not address the specific  
19 test year adjustments to SPP expenses proposed by the Company in this case.

20

21 **Q. DO YOU HAVE OTHER CONCERNS REGARDING PSO'S PROPOSED TEST**

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<sup>70</sup> See page 54 of PSO Witness Hamlett's direct testimony.

<sup>71</sup> See page 54 of PSO witness Hamlett's direct testimony.

1           **YEAR ADJUSTMENTS TO SPP EXPENSES?**

2    A.    Yes.  The third-party charges underlying the amounts billed from SPP that PSO seeks to  
3           recover include projected costs that are subject to future true-up.  The final amount of  
4           these third-party charges is not known at this time.  Moreover, in most cases such  
5           charges are made pursuant to formula rates that have been administratively approved by  
6           the FERC in instances where no party (such as PSO) has intervened to question the  
7           reasonableness of the proposed formula rates.  For example, PSO indicates that over the  
8           last five years the Company has intervened in only 4 cases before the FERC to challenge  
9           third party formula rates.<sup>72</sup>  Given the lack of PSO involvement in review of these third  
10          party transmission rates, and the fact that the rates are based on projected costs that are  
11          subject to future true-ups, PSO's proposed adjustments to annualize test year SPP  
12          charges fail to meet the "reasonable and necessary" and "known and measureable"  
13          standards that have been traditionally applied in determining allowable base rate  
14          expenses in Oklahoma and other jurisdictions. (Title 17 O.S. § 284)

15  
16    **Q.    DO YOU HAVE OTHER CONCERNS REGARDING PSO'S PROPOSED TEST**  
17    **YEAR ADJUSTMENTS TO SPP EXPENSES?**

18    A.    Yes.  The SPP charges that PSO seeks to recover in base rates include charges from the  
19          Company's affiliate, Oklahoma Transco.  PSO indicates that Oklahoma Transco charges  
20          include a 11.2% return on equity (ROE) component, which is significantly higher than  
21          the ROE authorized for PSO in the Company's last Oklahoma retail rate case.<sup>73</sup>  It is

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<sup>72</sup> See Exhibit SN-1, PSO's response to OIEC 7-19.

<sup>73</sup> See Exhibit SN-2, PSO's response to OIEC 14-19.

1 inappropriate for PSO to ask its Oklahoma customers to pay affiliate charges based on a  
2 11.2% ROE when the Company's own allowed ROE for constructing the same lines  
3 would have been far lower.

4  
5 **Q. WHAT IS YOUR RECOMMENDATION REGARDING PSO'S REQUESTED**  
6 **TEST YEAR ADJUSTMENTS TO SPP EXPENSES?**

7 A. I recommend that PSO's proposed test year adjustments to annualize SPP Network  
8 Integration Transmission Service Costs and Oklahoma Transco Base Plan Costs be  
9 rejected since the Company has not demonstrated that such increases meet the  
10 reasonable, necessary, and known and measurable standards for recovery through base  
11 rates. This recommendation results in a \$16.06 million reduction to the level of SPP  
12 charges which PSO proposes to recover through its new base rates.

**(1) SPP CHARGES COLLECTED THROUGH PSO'S SPPTC TARIFF**

13 **Q. WHAT LEVEL OF SPP CHARGES WAS COLLECTED THROUGH PSO'S**  
14 **SPPTC TARIFF DURING THE TEST YEAR?**

15 A. PSO's testimony in this case indicates that the Company collected approximately \$42.88  
16 million of SPP charges through its SPPTC Tariff during the test year.<sup>74</sup>

17  
18 **Q. WHAT IS THE NATURE OF THE CHARGES COLLECTED BY PSO**  
19 **THROUGH THE SPPTC TARIFF?**

---

<sup>74</sup> See Table on page 54 of PSO Witness Hamlett's direct testimony.

1 A. The charges recoverable through the SPPTC Tariff are projected Base Plan (Schedule 11  
2 of the SPP Open Access Transmission Tariff) charges, including any credits or refunds,  
3 associated with projects constructed by third party transmission owners, excluding  
4 Oklahoma Transco.<sup>75</sup>

5  
6 **Q. DOES PSO HAVE ANY SPECIFIC OBLIGATIONS TO DEMONSTRATE THE**  
7 **REASONABLENESS OF AMOUNTS IT SEEKS TO RECOVER THROUGH**  
8 **THE SPPTC TARIFF?**

9 A. Yes. The SPPTC Tariff defines PSO's obligations to support charges recovered under  
10 this rider as follows:

11 Beginning in 2015, and continuing each year thereafter, the Company  
12 will file re-determined SPPTC factors according to these tariff  
13 provisions. Calculations for the re-determined rates shall be made by  
14 the application of the SPPTC formula set forth in this tariff. The  
15 Company shall file information sufficient to document and support the  
16 reasonableness of the projected SPP Expenses, the True-up amounts  
17 during the previous period, and the re-determined SPPTC rates with  
18 each annual re-determination.

19 With the filing, the company shall provide the projected revenue  
20 impact of the annual SPP Expense re-determination for each major  
21 customer class. The company shall also provide any information or  
22 studies regarding the economic benefit or analysis to customers  
23 associated with the eligible incremented SPP expenses.

24  
25 The company will address the reasonableness of SPP Expenses  
26 collected through the SPPTC during the next PSO base rate case and in  
27 future base rate cases. Based on the review by the Commission Staff  
28 and parties in the next base rate case, any over or under recovery of  
29 SPP Expenses collected through the SPPTC shall be refunded to or

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<sup>75</sup> See Exhibit SN-3, page 1 of PSO's SPPTC Tariff.

1 collected from customers with interest calculated at the applicable  
2 Commission established interest rate applied to customer deposits for  
3 deposits held one year or less, or the interest rate applied to customer  
4 deposits held for more than one year.

5 **Q. HAS PSO MET THE ABOVE REQUIREMENTS TO SUPPORT THE**  
6 **REASONABLENESS OF EXPENSES COLLECTED THROUGH ITS SPPTC**  
7 **TARIFF IN THIS CASE?**

8 A. No. Except for the brief mention of the SPPTC charges in Mr. Hamlett's testimony, no  
9 PSO witness addresses the reasonableness of specific charges collected through the  
10 SPPTC during the test year or in periods since the test year in the Company's last base  
11 rate case.<sup>76</sup>

12  
13 **Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?**

14 A. PSO has failed to adhere to the explicit requirement of the SPPTC Tariff with regards to  
15 demonstrating the reasonableness of past expenses collected through the SPPTC. For  
16 this reason, I recommend that PSO be ordered to refund the \$42.88 million of test year  
17 charges collected through the SPPTC, with interest, over a three-year period.

18  
**IV. RECOVERY OF THE NORTHEASTERN UNIT 4 PLANT COSTS**

19 **Q: PLEASE DESCRIBE THE ISSUES SURROUNDING PSO'S REQUESTED**  
20 **RECOVERY OF THE NORTHEASTERN UNIT 4 PLANT COSTS IN THIS**  
21 **CASE?**

22 A: PSO is proposing to retire the 460MW Northeastern Unit 4 coal plant in the middle of its

1 useful life, but plans to continue to include both a “return on” and a “return of” the plant  
2 costs in rates. Thus, there are two cost recovery issues associated with this plant  
3 retirement:

4 1. Should PSO continue to include the un-depreciated balance of this plant  
5 in rate base, enabling the Company to continue to earn a full profit “return on” the  
6 abandoned plant for its shareholders; and

7 2. Should PSO continue to depreciate the balance of this plant into rates so  
8 that shareholders will receive a full “return of” the abandoned plant costs; and  
9

10 **Q: WHAT ARE THE COSTS TO RATEPAYERS AS A RESULT OF THE**  
11 **COMPANY’S PROPOSALS?**

12 A: The net un-depreciated plant balance for Northeastern Units 4 at June 30, 2017 was  
13 \$82.7 million,<sup>77</sup> and the associated ADIT balance was \$32 million, for a net investment  
14 in rate base for Unit 4 of \$50.7 million.<sup>78</sup> The annual rate base “return on” this amount  
15 would be \$5.2 million. Annual depreciation expense on the Unit 4 assets is  
16 approximately \$4.1 million,<sup>79</sup> making the total annual cost to ratepayers about \$9.3  
17 million.  
18

19 **Q: DO YOU AGREE WITH THE COMPANY’S PROPOSED TREATMENT?**

20 A: No. I do not agree with PSO’s proposal to include the costs of the retired Northeastern

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<sup>76</sup> See Exhibit SN-3, page 1 of PSO’s SPPTC Tariff.

<sup>77</sup> See PSO response to OIEC 9-4.

<sup>78</sup> Id.

<sup>79</sup> See PSO’s Response to AG 10-4.

1 Unit 4 in rates. Oklahoma law is very clear on this point: only assets “used and useful”  
2 for providing utility service may be included in rate base. Further, a plant’s “used and  
3 useful” status is determined “based upon the value of the property used and useful in [the  
4 utility’s] public service business at the time the inquiry was made.”<sup>80</sup> In other words, the  
5 determination is made in each rate case as to whether assets are used and useful at that  
6 time and, thus, should be included in rates. Under the “used and useful” test, only assets  
7 in service during the test year plus six months may be used to establish rates.<sup>81</sup> As  
8 explained by the Oklahoma Supreme Court in *Southwestern Public Service Co.*, 1981  
9 OK 136, ¶ 14, 637 P.2d at 98:

10 A test year is a mirror view of the past suspended within a limited but  
11 definite time frame through which we prophesy its duplication in the  
12 future. To alter the image is to risk the distortion for the future. Only the  
13 cost of those capital assets which are in actual use during the test year, or  
14 whose use is so imminent and certain that they may be said, at least by  
15 analogy, to have the quality of working capital may be added to the rate  
16 base established by the test year in any event; and then only if appropriate  
17 counter-balancing safe guards are applied. (Emphasis added).

18 **Q: DO YOU BELIEVE THAT THE “USED AND USEFUL” STANDARD AS**  
19 **APPLIED IN OKLAHOMA PRECLUDES THE TREATMENT PROPOSED BY**

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<sup>80</sup> *Turpen v. Oklahoma Corporation Commission*, 1988 OK 126, n. 7, 769 P.2d 1309, 1316 (In Oklahoma, a public utility’s rate base is “the amount upon which the utility is permitted to make a profit,” which is “based upon the value of the property used and useful in [the utility’s] public service business at the time the inquiry was made.”) (quoting *Southwestern Public Service Co. v. State*, 1981 OK 136, 637 P.2d 92, 97).

<sup>81</sup> See *Southwestern Public Service Co. v. State*, 1981 OK 136, 637 P.2d 92, 97; *Arkansas Louisiana Gas Co. v. Sun Oil Co.*, 1976 OK 89, 554 P.2d 14, 15. See also *Public Service Co. v. Oklahoma Corp. Com.*, 1983 OK 124, 688 P.2d 1274, 1276; *Oklahoma Natural Gas Co. v. Corporation Com. of Oklahoma*, 1923 OK 400, 216 P. 917.

In 1994, the test year was effectively extended by six months when the Legislature adopted Okla. Stat. tit. 17, § 284, which authorized recovery of costs reasonably certain to occur within six months of the test year end.

1           **THE COMPANY?**

2    A:    Yes.  After Northeastern Unit 4 closed, the plant is no longer providing service to  
3           customers, and thus is no longer used and useful, and therefore cannot be included in  
4           rates under a used and useful determination.  In Oklahoma, a utility is allowed to earn a  
5           reasonable return on utility assets at the time the assets are being used for the public.<sup>82</sup>

6  
7    **Q:    WAS UNIT 4 ACTUALLY IN SERVICE AT THE END OF THE 6-MONTH**  
8           **PERIOD AFTER TEST YEAR END?**

9    A:    No.  Unit 4 was taken out of service in April 2016 to coincide with the in-service dates  
10           of the \$221 million of new plant investments at Northeastern 3 and other gas plants to  
11           meet PSO's proposed ECP.  When the new ECP assets are included in rates, Unit 4  
12           should be taken out of rates.  At a minimum, the return on the investment in Unit 4  
13           should be taken out of rates, because this plant is no longer being used to provide service  
14           to Oklahoma ratepayers.

15  
16   **Q:    ARE THERE RELEVANT EXAMPLES IN OTHER STATES WHERE**  
17           **COMMISSIONS HAVE DENIED RECOVERY OF RETIRED COAL PLANT**  
18           **COSTS?**

19   A:    Yes, there is a particularly relevant example that occurred in AEP's home state of Ohio.  
20           There, the Ohio Commission *denied* AEP-Ohio Power's request for recovery of costs

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<sup>82</sup> See, *Southwestern Public Service Co.*, 637 P.2d 92, 97 (Okla. 1981) where the Court stated: "In determining whether the rate is reasonable, it is necessary to ascertain the fair value of the property of the [utility] used and useful in its public service business at the time the inquiry was made, . . . for [the utility] 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."

1 associated with the retirement of its Sporn 5 unit.<sup>83</sup> Sporn 5 was a 450MW coal plant  
2 that was built and placed in service around 1960. AEP sought to close the coal unit as  
3 part of an agreement between AEP and the Department of Justice, and asked that the  
4 Ohio commission approve recovery of the remaining costs of the plant, with return, over  
5 an accelerated recovery period, similar to the treatment PSO seeks here. In its order  
6 dated January 11, 2012, the Ohio commission denied any recovery of the remaining costs  
7 of the closed unit, finding that the plant did not meet the “used and useful” requirements  
8 in Ohio.<sup>84</sup>

9  
10 **Q: ARE THERE EXAMPLES FROM OTHER STATES WHERE UTILITIES HAVE**  
11 **AGREED TO WRITE-OFF THE COSTS OF ABANDONED COAL PLANTS?**

12 **A:** Yes. In a contemporaneous Regional Haze case in New Mexico, Public Service  
13 Company of New Mexico (“PNM”) has agreed to write-off 50% of the stranded costs  
14 associated with two coal units retired as part of its environmental compliance plan for  
15 Regional Haze. PNM is a vertically integrated public utility subject to the jurisdiction of  
16 the New Mexico commission. One of PNM's coal facilities, the San Juan Generating  
17 Station (“SJGS”), consists of four coal-fired units with 1,683 net megawatts (“MW”) of  
18 electric generation capacity. PNM’s Revised SIP sought approval to (a) abandon two  
19 coal plants at San Juan Units 2 and 3 and (b) issue Certificates of Public Convenience  
20 and Necessity (“CCN”) for replacement power resources. As part of the settlement in

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<sup>83</sup> See Order of the PUC of Ohio in Case No. 10-1454-EL-RDR.

<sup>84</sup> Id.

1 that case, PNM has agreed to write-off \$148,555,743, which represents 50% of the  
2 stranded book value of the plant assets plus about \$20M in other associated costs.<sup>85</sup>

3  
4 **Q: WOULD YOU CONSIDER THE RETIRED PSO COAL PLANT COSTS TO BE**  
5 **“STRANDED COSTS” UNDER THE TRADITIONAL UTILITY DEFINITION**  
6 **OF THAT WORD?**

7 A: No. Costs are not “stranded” when a utility voluntarily chooses to retire an asset in the  
8 middle of its useful life, as AEP/PSO has done here. I know of no order, case law or  
9 statute where costs have been defined as stranded costs when they result from a utility’s  
10 voluntary action. To the contrary, costs have been defined as stranded when they were  
11 caused by laws or orders that mandate a major change. Here, there is no mandate that  
12 the utility close the Northeastern plant. Neither the SIP nor the FIP require such action.  
13 In fact, the FIP provides that the Northeastern units be retrofitted and continue operating.

14  
15 **Q: EVEN WITHOUT SPECIFIC LAWS THAT MANDATE A MAJOR CHANGE,**  
16 **COULD THERE BE OTHER SITUATIONS THAT STRAND UTILITY ASSETS?**

17 A: Utility assets can become uneconomic, where it costs ratepayers more to keep the assets  
18 in service than to replace them. In that case, the costs of the stranded assets might be  
19 shared with ratepayers. Here, that is certainly not the case. According to Mr. Norwood's  
20 testimony in Cause Nos. PUD 201200054 and PUD 201500208, the Company’s own  
21 analysis shows that the nominal cost of the Retrofit Both Units option (keeping the assets  
22 in service) is approximately \$2 billion lower than the cost of the EPA Settlement plan

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<sup>85</sup> See testimony of Gerald Ortiz filed on August 28, 2015 in NMPRC Case No. 13-00390-UT.

1 (taking the assets out of service). I know of no ratemaking theory that would require  
2 ratepayers to share the costs of retired assets, when such retirement results in higher, not  
3 lower, rates.  
4

5 **Q: ARE THERE OTHER REASONS WHY RATEPAYERS SHOULD NOT BE**  
6 **RESPONSIBLE FOR THE REMAINING COAL PLANT COSTS?**

7 A: Yes. According to the Company's own analysis, and to Mr. Norwood's testimony in the  
8 above-referenced causes, the EPA settlement plan was not the least-cost option for  
9 ratepayers. Instead, it appears to be a business decision of the Company that inures to  
10 the overall benefit of AEP. As such, AEP, not the Oklahoma ratepayers, should bear the  
11 additional costs of closing coal units in the prime of their useful life.  
12

13 **Q: WHAT DO YOU RECOMMEND WITH RESPECT TO PSO'S PROPOSAL TO**  
14 **INCLUDE UNIT 4 IN RATE BASE?**

15 A: I recommend that the return on Unit 4 be suspended because the assets are no longer  
16 *used and useful* for providing service. The impact of this adjustment is \$9.37 million, as  
17 shown at Exhibit MG 2.7. I also recommend that, because the assets are no longer in  
18 rate base, that depreciation expense on the assets also be removed from rates. At some  
19 point in the future, however, if the plant is re-powered or converted to gas and produces  
20 net benefits to ratepayers, the plant could be deemed *used and useful* at that time and  
21 could be included in rate base.  
22

1 **Q: ARE YOU AWARE OF RELEVANT EXAMPLES OF THIS SITUATION,**  
2 **WHERE A PLANT IS REMOVED FROM RATE BASE BECAUSE IT IS NO**  
3 **LONGER *USED AND USEFUL* BUT ALLOWED TO COME BACK INTO RATE**  
4 **BASE IN THE FUTURE IF IT BECOMES *USED AND USEFUL* AGAIN AT**  
5 **SOME POINT?**

6 A: Yes. In 1991, in an El Paso Electric Company (“EPEC”) rate case, the Texas Public  
7 Utility Commission disallowed the Palo Verde Unit 3 costs because the plant represented  
8 excess capacity.<sup>86</sup> However, the Texas Commission also determined that an incremental  
9 schedule for inclusion of Palo Verde Unit 3 in rate base would be a measured approach  
10 that would be consistent with the plant becoming used and useful over time.<sup>87</sup> In the  
11 interim, the plant was allowed to operate, but it was not allowed full rate base recovery  
12 until it was actually used and useful and no longer merely supplying excess capacity.  
13 The Texas PUC’s decision was upheld by the Texas Court of Appeals in 1995.<sup>88</sup>

14  
15 **Q: ARE YOU AWARE OF OTHER INSTANCES WHERE COMMISSIONS HAVE**  
16 **ALLOWED PARTIAL RECOVERY OF EXCLUDED PLANT?**

17 A: Yes. Public Service Company of Oklahoma’s (“PSO”) Black Fox nuclear plant was  
18 under construction in 1980 when the Oklahoma Commission evaluated the economic  
19 feasibility of completing the plant. Although construction had begun on the plant in

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<sup>86</sup> See Order on Rehearing in Docket No. 9945, signed February 6, 1992, at page 7 of Attachment 1.

<sup>87</sup> Id. In its order, the Texas commission approved a gradual inclusion of the Palo Verde unit into rate base based on a 0%-40%-65%-85%-100% schedule designed to correspond to the plant becoming used and useful over time to satisfy the utility’s anticipated future capacity requirements.

<sup>88</sup> See *El Paso Electric Company v Public Utility Comm’n*, No.03-93-0061-CV, Court of Appeals of Texas, Third District, Austin, July 12, 1995.

1 1973, the Oklahoma commission was forced to evaluate the economic feasibility of  
2 completing the project when the Three Mile Island nuclear plant accident occurred in  
3 1979. The following year, in PSO's 1980 rate case the Oklahoma commission  
4 considered whether the project should continue, and addressed how the costs already  
5 incurred should be treated for ratemaking purposes. In its order, at page 53, the  
6 Oklahoma Commission determined that (1) the project was no longer economically  
7 feasible, (2) the \$132 million costs of the project, in construction work in progress  
8 (CWIP) at the time, should not be included in rate base, and (3) any costs incurred after  
9 the date of the order would be considered imprudent. Because the costs of construction  
10 had been prudently incurred, up to the date of the order, the Oklahoma Commission  
11 allowed PSO to amortize the costs of the project into rates over a 10-year period. The  
12 balance, however, was not allowed in rate base.

13 With respect to the return that should be allowed on the balance, the Oklahoma  
14 Commission said at page 60 of its order:

15 We conclude, based upon the testimony presented to us, that a full return  
16 would reward the equity owner unnecessarily, while no return on this  
17 capital investment would tell bondholders and preferred stockholders that  
18 they are not protected from risks which are normally attributable to equity  
19 holders of a company. We believe that capital recovery is essential to the  
20 financial health of Public Service Company and it is imperative that the  
21 investment community retain confidence in this Company. Accordingly,  
22 we find that the debt and preferred portion amortized loss associated with  
23 a Black Fox recovery should carry their actual costs as established in this  
24 case, but that no return be included for the equity portion. Should it  
25 become necessary in subsequent rate cases in order to maintain this  
26 Company's financial integrity and its ability to attract capital at reasonable  
27 cost for the benefit of Oklahoma ratepayers we will consider among other  
28 things a partial return to the equity holder. (Emphasis added).

29 Thus, the OCC provided no return on the equity portion of the Black Fox investment,

1 but, in order to protect the financial health of the utility, did allow a debt return to the  
2 bondholders.

3  
4 **Q: WITH RESPECT TO NORTHEASTERN UNIT 4, IS THERE A RANGE OF**  
5 **RATEMAKING REMEDIES AVAILABLE TO THE COMMISSION BASED ON**  
6 **THE DISCUSSION ABOVE?**

7 A: Yes. Based on the fact that the plant is no longer in service and, thus, is no longer used  
8 and useful to ratepayers, the Commission would be fully justified in excluding Unit 4  
9 from rate base in its entirety and disallowing any associated depreciation expense as  
10 well. There is, however, at least one other alternative. The Commission could exclude  
11 the plant for now, and then allow some portion of costs into rate base over time as the  
12 plant becomes used and useful, if the plant is one day converted to a natural gas plant or  
13 re-powered as a coal plant in the future.

14  
15 **Q: REGARDING THE THIS OPTION, WHERE THE COMMISSION EXCLUDES**  
16 **THE PLANT NOW BUT HOLDS OPEN THE OPTION TO INCLUDE THE**  
17 **PLANT IN RATE BASE IN THE FUTURE IF THE PLANT IS PLACED BACK**  
18 **INTO SERVICE, AND IT BECOMES USED AND USEFUL ONCE AGAIN, DO**  
19 **YOU KNOW OF ANY EXAMPLES OF THIS TREATMENT?**

20 A: Yes. In 1987, OG&E took its Arbuckle plant out of service in response to load lost in  
21 the economic downturn that occurred at that time.<sup>89</sup> With plans to return the plant to  
22 service when the economy recovered, OG&E sought to include the Arbuckle plant in

1 rate base in its 1991 rate case, PUD 91-1055.<sup>90</sup> The Commission, however, found that  
2 the plant was not used and useful while it was not in service, and as a result, could not be  
3 included in rate base.<sup>91</sup> The Commission did allow OG&E to accrue a carrying charge  
4 on the Arbuckle plant balance that it said would be included in rate base if and when the  
5 plant was ever returned to service.<sup>92</sup> If the plant, however, was never returned to service,  
6 the carrying charge would not be recovered from ratepayers.<sup>93</sup>

7  
8 **Q: DID OG&E CONTINUE TO DEPRECIATE THE ARBUCKLE PLANT?**

9 A: No. With the plant excluded from rate base the utility was not able to include the plant's  
10 depreciation expense in rates. In effect, the Arbuckle plant became Plant Held for Future  
11 Use. As such, the *return on* and the *return of* the plant were both excluded from rates.

12  
13 **Q: DOES PSO HAVE PLANS TO BRING THE NORTHEASTERN UNIT BACK ON**  
14 **LINE AT SOME POINT IN THE FUTURE?**

15 A: It might. In response to AG Data Request 5-8, the Company provided its latest (2015)  
16 IRP. On pages 84 and 85 of the IRP, PSO states that it is retiring Northeastern Unit 4 in  
17 2016, which provides PSO the opportunity to consider the possibility of re-powering that  
18 Unit.

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<sup>89</sup> Commission Order No. 480443 in Cause No. PUD 910001055 at page 15.

<sup>90</sup> Id.

<sup>91</sup> Id.

<sup>92</sup> Id.

<sup>93</sup> Id.

1           **Q: DID YOU REVIEW THE TESTIIMONY OF MR. FATE ON THE**  
2           **NORTHEASTERN4 ISSUE?**

3           A: Yes. At page 16 of his testimony, Mr. Fate makes the statement that the Northeastern  
4           plant served customers for 46 years, which was beyond the original retirement date of  
5           the plant. The truth is that the original retirement dates for these coal units were wrong.  
6           These dates were later corrected by the Commission and set at 2040. Thus, PSO retired  
7           Unit 4 in the middle of its useful life with 24 years left in the plant.

8  
9           **Q: WHAT DO YOU RECOMMEND?**

10          A: The Commission would be justified in excluding the entire cost of the plant from rate  
11          base and disallowing associated depreciation expense recovery as well. Of course, a  
12          complete disallowance could be revisited by the Commission over time, in response to  
13          changed circumstances regarding either PSO's financial health, or the extent to which  
14          Northeastern 4 eventually becomes used and useful, or both. The OCC took this  
15          approach in the final sentence of the excerpt from the Black Fox case above.

16                 Even without a prudence finding, however, the Northeastern Unit 4 plant balance  
17          should be excluded from rate base because the plant is no longer *used and useful*. In  
18          Oklahoma, only plant used and useful for the provision of service can be included in rate  
19          base. Once removed from rate base, the depreciation expense on the plant should be  
20          removed as well. This means that the *return on* and *return of* Northeastern 4 would not  
21          be collected from ratepayers at this time.

22                 Finally, if the Commission finds that PSO is leaving open the option to return

1 Northeastern 4 to service in the future, the Commission could classify the plant as Plant  
2 Held for Future Use. This would exclude the plant from rate base and discontinue its  
3 depreciation as well, but would leave open the possible return of the plant to rate base if  
4 the plant is eventually returned to service – either converted or repowered – in the future.

V. **ADJUSTMENTS PROPOSED BY OTHER OIEC WITNESSES**

5 **Q: WHAT IS THE IMPACT OF THE ADJUSTMENTS PROPOSED BY OTHER**  
6 **OIEC WITNESSES?**

7 A: OIEC witness David J. Garrett addresses PSO's depreciation study. Mr. Garrett's  
8 recommended depreciation rates, when applied to June 30, 2017 plant balances, result in  
9 a reduction of \$33,203,149 to PSO's proposed increase as shown at *Exhibit MG-2.11*.

10 OIEC witness David Parcell addresses return on equity and other cost of capital  
11 issues. The impact of Mr. Parcell's adjustments result is a reduction of \$18,759,270 as  
12 set forth at *Exhibit MG-2 and MG-2.12*.

VI. **CONCLUSION**

13 **Q: DO YOU HAVE ANY FURTHER COMMENTS?**

14 A: Yes. My recommendations do not address every potential issue affecting PSO's revenue  
15 requirement. I addressed many of what I considered to be the material issues in this  
16 case. The fact that I did not express an opinion on a particular issue is not to be  
17 interpreted as agreement with the Company's position on my part.

18  
19 **Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?**

1 A: Yes, it does. However, I reserve the right to update and amend my revenue requirement  
2 recommendations based on the responsive testimony filed by other parties and the  
3 rebuttal testimony filed by PSO. My recommendations in the rate design phase may also  
4 affect my overall revenue requirement recommendations.



**MARK E. GARRETT**

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**EDUCATION:**

Juris Doctor Degree, With Honors, Oklahoma City University Law School, 1997  
Post Graduate Hours in Accounting, Finance and Economics, 1984-85:  
University of Texas at Arlington; University of Texas at Pan American;  
Stephen F. Austin State University  
Bachelor of Arts Degree, University of Oklahoma, 1978

**CREDENTIALS:**

Member Oklahoma Bar Association, 1997, License No. 017629  
Certified Public Accountant in Oklahoma, 1992, Certificate No. 11707-R  
Certified Public Accountant in Texas, 1986, Certificate No. 48514

**WORK HISTORY:**

**GARRETT GROUP, LLC – Regulatory Consulting Practice (1996 - Present)** Participates as a consultant and expert witness in electric utility, natural gas distribution company, and natural gas pipeline matters before regulatory agencies making recommendations related to cost-based rates. Reviews management decisions of regulated utility companies for reasonableness from a ratemaking perspective especially regarding the reasonableness of prices paid for natural gas supplies and transportation, coal supplies and transportation, purchased power and renewable energy projects. Participates in gas gathering, gas transportation, gas contract and royalty valuation disputes to determine pricing and damage calculations and to make recommendations concerning the reasonableness of charges to royalty and working interest owners and other interested parties. Participates in regulatory proceedings to restructure the electric and natural gas utility industries. Participates as an Instructor at NMSU Center for Public Utilities and as a Speaker at NARUC Staff Subcommittee on Accounting and Finance.

**OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1994)** Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

**FREEDOM FINANCIAL CORPORATION - Controller (1987 - 1990)** Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

**SHELBY, RUCKSDASHEL & JONES, CPAs - Auditor (1986 - 1987)** Audited the financial statements of businesses in the state of Texas, with an emphasis in financial institutions.

## Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

1. **Anchorage Municipal Light and Power (Alaska), 2017 (Docket No. U-17-008)** – Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony in ML&P’s General Rate Case on various revenue requirement and rate design issues.
2. **Oncor Electric Delivery Company (Texas), 2017 (PUC Docket No. 46957)** – Participating as an expert witness on behalf of the Steering Committee of Cities before the Texas Public Utility Commission in Oncor’s General Rate Case proceeding to provide testimony on various revenue requirement issues.
3. **EverSource (Massachusetts), 2017 (DPU Docket No. 17-05)** – Participating as an expert witness before the Massachusetts Department of Public Utilities EverSource’s General Rate Case application on behalf of Energy Freedom Coalition of America to provide testimony to address various revenue requirement issues.
4. **El Paso Electric Company (Texas), 2017 (PUC Docket No. 46831)** – Participating as an expert witness on behalf of the City of El Paso before the Texas Public Utility Commission in El Paso’s General Rate Case proceeding to provide testimony on various revenue requirement issues.
5. **Atmos Pipeline Texas (Texas), 2017 (Docket No. 10580)** – Participating as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in APT’s General Rate Case application, sponsoring testimony to address various revenue requirement proposals.
6. **Empire District Electric Company (Oklahoma), 2017 (Cause No. PUD 201600468)** – Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”)<sup>1</sup> before the Oklahoma Corporation Commission in Empire’s General Rate Case application. Sponsoring testimony to address the utility’s overall revenue requirement and rate design proposals.
7. **Caesars Enterprise Service, LLC (Nevada), 2016 (704B Exit Application)** – Participating as an expert witness on behalf of Caesars before the Nevada PUC. Sponsoring written and oral testimony in Caesar’s application to purchase energy and capacity from a provider other than Nevada Power.
8. **Southwestern Electric Power Company (Texas), 2016 (PUC Docket No. 46449)** – Participating as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s general rate case proceeding to provide testimony on various revenue requirement issues.
9. **CenterPoint Texas, 2016 (Docket No. 10567)** – Participating as an expert witness on behalf of City of Houston before the Texas Railroad Commission in CenterPoint’s general rate case application, sponsoring testimony to address the utility’s overall revenue requirement and various rate design proposals.
10. **Entergy Texas, Inc., 2016 (Docket No. 46357)** – Participating as an expert witness on behalf Cities Served by Applicant before the Texas PUC in ETI’s application to amend its Transmission Cost Recovery Factor.
11. **Anchorage Municipal Light and Power, 2016 (Docket No. U-16-060)** – Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to

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<sup>1</sup> OIEC is an association of large commercial and industrial customers in Oklahoma.

provide testimony on the ratemaking treatment of ML&P's acquired interest in the Beluga River Unit gas field with ratepayer funds.

12. **Arizona Public Service Company, 2016 (Docket No. E-01345A-16-0036)** – Participating as an expert witness before the Arizona Corporation Commission in APS's General Rate Case application on behalf of Energy Freedom Coalition of America to provide written and oral testimony to address various revenue requirement issues.
13. **Oklahoma Gas & Electric Co. (Arkansas), 2016 (Docket No. 16-052-U)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC")<sup>2</sup> before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.
14. **Sierra Pacific Power Company, 2016 (Docket No. 16-06006)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers<sup>3</sup> before the Nevada PUC in SPPC's general rate case proceeding. Sponsored testimony on various revenue requirement, depreciation, and rate design issues.
15. **Tucson Electric Power, 2016 (Docket No. E-01933A-15-0322)** – Participating as an expert witness before the Arizona Corporation Commission in TEP's General Rate Case application; on behalf of Energy Freedom Coalition of America providing written and oral testimony to address the utility's cost of service study and rate design proposals.
16. **Texas Gas Service, 2016 (Docket No. 10506)** – Participated as an expert witness on behalf of El Paso before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.
17. **Texas Gas Service, 2016 (Docket No. 10488)** – Participated as an expert witness on behalf of South Jefferson County Service Area ("SJCSA") before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.
18. **Oklahoma Gas and Electric Company, 2016 (Cause No. PUD 201500273)** – Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.
19. **Oklahoma Gas & Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation ("DG") rates for solar DG customers.
20. **Anchorage Municipal Light and Power, 2016 (Docket No. U-13-097)** – Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on rates and tariffs proposed for customer-owned combined heat and power plant generation.
21. **Oklahoma Natural Gas Company, 2015 (Cause No. PUD 201500213)** – Participated as an expert

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<sup>2</sup> ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

<sup>3</sup> The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG's General Rate Case application. Sponsored testimony to address the utility's overall revenue requirement and rate design proposals.

22. **Oklahoma Gas & Electric Company, 2015 (Cause No. PUD 201500274)** – Participated as an expert witness on behalf of The Alliance for Solar Choice (“TASC”) before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation (“DG”) rates for solar DG customers.
23. **Nevada Power Company, 2015 (Docket No. 15-07004)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”)<sup>4</sup> before the Nevada PUC. Sponsoring written and oral testimony in NPC's 2015 Integrated Resource Plan to provide analysis of the On Line transmission line allocation, the Siverhawk plant acquisition, and the Griffith contract termination.
24. **Oklahoma Gas & Electric Company, 2015 (Docket No. 15-034-U)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”) before the Arkansas Public Service Commission in OG&E's Act 310 application to implement a rider to recover environmental compliance costs.
25. **MGM Resorts, LLC, 2015 (Docket No. 15-05017)** – Participated as an expert witness on behalf of the MGM Resorts, LLC before the Nevada PUC. Sponsoring written and oral testimony in MGM's application to purchase energy and capacity from a provider other than Nevada Power.
26. **Entergy Arkansas, 2015 (Docket No. 15-015-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”) an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.
27. **Public Service Company of Oklahoma, 2015 (Cause No. PUD 201500208)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.
28. **Nevada Power Company, 2014 (Docket No. 14-05003)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored written and oral testimony in NPC environmental compliance case, called the Emissions Reduction and Capacity Replacement case. The main focus of our testimony was our recommendation to eliminate the \$438M Moapa solar project from the compliance plan.
29. **Nevada Power Company, 2014 (Docket No. 14-05004)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsor written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
30. **Oklahoma Gas and Electric Co., 2014 (Cause No. PUD 201400229)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) in OG&E's Environmental Compliance and Mustang Modernization Plan before the Oklahoma Corporation Commission to provide testimony addressing the economics and rate impacts of the plan.

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<sup>4</sup>The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.

31. **Sourcegas Arkansas, Inc., 2014 (Docket No. 13-079-U)** Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”), an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in SGA’s general rate case to provide testimony on various revenue requirement issues.
32. **Anchorage Municipal Light and Power, 2014 (Docket No. U-13-184)** – Participated as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on various revenue requirement and cost of service issues.
33. **Public Service Company of Oklahoma, 2014 (Cause No. PUD 201300217)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s general rate case application to provide testimony on various cost-of-service issues and on the utility’s overall revenue requirement and rate design proposals.
34. **Entergy Texas Inc., 2013 (PUC Docket No. 41791)** – Participated as an expert witness on behalf of the Cities<sup>5</sup> in ETI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
35. **MidAmerican/NV Energy Merger, 2013 (Docket No. 13-07021)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored testimony to address various issues raised in the proposed acquisition of NV Energy by MidAmerican Energy Holdings Company, including capital structure and acquisition premium recovery issues.
36. **Entergy Arkansas, 2013 (Docket No. 13-028-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”) an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy’s general rate case to provide testimony on various revenue requirement issues.
37. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers<sup>6</sup> before the Nevada PUC in SPPC’s general rate case proceeding to provide testimony on various cost of service and revenue requirement issues. Sponsored written and oral testimony in the depreciation phase, the revenue requirement phase and the rate design phase of these proceedings.
38. **Gulf Power Company, 2013 (Docket No. 130140-EI)** – Participated as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power’s general rate case proceeding to provide testimony on various revenue requirement issues.
39. **Public Service Company of Oklahoma, 2013 (Cause No. PUD 201200054)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission (“OCC”) to provide testimony in PSO’s application seeking Commission approval of its settlement agreement with EPA.
40. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s general rate case proceeding to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.

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<sup>5</sup> The Cities include Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange.

<sup>6</sup> The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

41. **Doyon Utilities, 2012 Alaska Rate Case** (Docket No. TA7-717) – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.
42. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University’s general rate case with the Corix Group, which provides utility services to the University.
43. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility’s request to earn additional compensation on a 510MW purchased power agreement with Exelon
44. **Centerpoint Energy Texas Gas, 2012 (Docket No. GUD 10182)** – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.
45. **Entergy Texas Inc., 2012 (PUC Docket No. 39896)** – Participated as an expert witness on behalf of the Cities in ETI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
46. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participated as an expert witness on behalf of the OIEC before the OCC in ONG’s Performance Based Rate (“PBR”) application seeking Commission approval of a requested rate increase based upon formula results for 2011.
47. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility services to the university.
48. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.
49. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participated as an expert witness on behalf of Enbridge before the OCC in Empire’s rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
50. **Nevada Power Company, 2011, (Docket No. 11-04010)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored written and oral testimony to address proposed changes to the Company’s customer deposit rules.
51. **Nevada Power Company, 2011, (Docket No. 11-06006)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
52. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participated as an

expert witness on behalf of the OIEC before the OCC in PSO's application seeking rider recovery of third party SPP transmission costs and fees.

53. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
54. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-109-U)** – Participated as an expert witness on behalf of Gerdau Macsteel before the Arkansas Public Service Commission in OG&E's application to recover Smart Grid costs to make recommendations regarding the allocation of the Smart Grid costs.
55. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking to include retiree medical expense in the Company's pension tracker mechanism.
56. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of OIEC before the Oklahoma Corporation Commission in AEP/PSO's application to recover ice storm O&M expenses through a regulatory asset/rider mechanism to address tax impact and return issues in the proposed rider.
57. **Public Service Company of Colorado, 2011 (Docket No. 10AL-908E)** – Participated as an expert witness on behalf of the Colorado Retail Council ("CRC") before the Colorado Public Utilities Commission providing written and live testimony to address PSCo's proposed Environmental Tariff.
58. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-067-U)** – Participated as an expert witness on behalf of the Northwest Arkansas Industrial Energy Consumers ("NWIEC")<sup>7</sup> before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.
59. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-146)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking rider recovery of third party SPP transmission costs and SPP administration fees.
60. **Massachusetts Electric Co. & Nantucket Electric Co. d/b/a National Grid, 2010 (Docket No. DPU 10-54)** – Participated as an expert witness providing both written and live testimony before the Massachusetts Department of Public Utilities on behalf of the Associated Industries of Massachusetts ("AIM") to address the Company's proposed participation in the 438MW Cape Wind project in Nantucket Sound.
61. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of the OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.
62. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

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<sup>7</sup> NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

63. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147)** – Participated as an expert witness on behalf of the Alliance of Xcel Municipalities (“AXM”) in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.
64. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participated as an expert-witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E’s 220MW self-build wind project.
65. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-29)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking pre-approval of deployment of smart-grid technology and rider-recovery of the associated costs. Sponsored written testimony to address smart-grid deployment and time-differentiated fuel rates.
66. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-01)** – Participated as an expert witness on behalf of the OIEC before the OCC in the Company’s proposed Green Energy Choice Tariff. Sponsored testimony to address the pricing and ratemaking treatment of the Company’s proposed wind subscription tariff.
67. **Nevada Power Company, 2010 (Docket No. 10-02009)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC to provide testimony in NPC’s Internal Resource Plan to address the ratemaking treatment of the proposed ON Line transmission line.
68. **Entergy Texas Inc., 2010 (PUC Docket No. 37744)** – Participated as an expert witness on behalf of the Cities in ETI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
69. **El Paso Electric Company, 2010 (PUC Docket No. 37690)** – Participated as an expert witness on behalf of the City of El Paso in the EPI general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
70. **Public Service Company of Oklahoma, 2009 (Cause No. 09-196)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application for approval of DSM programs and cost recovery. Sponsored testimony to address program costs, lost revenue recovery, cost allocations and incentives.
71. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 09-230 and 09-231)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E’s application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.
72. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E’s rate case. Provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
73. **Nevada Power Company, 2009, (Docket No. 08-12002)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

74. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031)** – Participated as an expert witness on behalf of OIEC before the OCC in PSO’s application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.
75. **Oklahoma Natural Gas Co., 2009 (Cause No. PUD 08-348)** – Participated as an expert witness on witness on behalf of the OIEC before the OCC in ONG’s application to establish a Performance Based Rate tariff. Sponsored both written and oral testimony to address the merits of the utility’s proposed PBR.
76. **Rocky Mountain Power, 2009 (Docket No. 08-035-38)** – Participated as an expert witness on behalf of the Division of Public Utilities (Staff) in PacifiCorp’s general rate case to provide testimony on various revenue requirement issues.
77. **Texas-New Mexico Power Co., 2008 (Docket 36025)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities (“ATM”) before the Texas PUC in TMNP’s general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
78. **Public Service Company of Oklahoma, 2008 (Cause No. 08-144)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s general rate case application to address revenue requirement and rate design issues to establish prospective cost-of-service based rates.
79. **Public Service Company of Oklahoma, 2008 (Cause No. 08-150)** – Participated as an expert witness on behalf of the OIEC before the OCC to address PSO’s calculation of its Fuel Clause Adjustment for 2008.
80. **Oklahoma Gas and Electric Company, 2008 (Cause No. PUD 08-059)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking authorization of its Demand Side Management (“DSM”) programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.
81. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334)** – Participated as an expert witness on behalf of the Cities in EGSI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
82. **Public Service Company of Oklahoma, 2008 (Cause No. 07-465)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application to recover the pre-construction costs of the cancelled Red Rock coal generation facility.
83. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO<sub>2</sub> allowances.
84. **Rocky Mountain Power, 2008 (Docket No. 07-035-93)** – Participated as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp’s general rate case to provide testimony on various revenue requirement issues.
85. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-449)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application seeking authorization of its

Demand Side Management (“DSM”) programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

86. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-397)** – Participated as an expert witness on behalf of OIEC before the OCC in PSO’s application seeking authorization to defer storm damage costs in a regulatory asset account and to recover the costs using the proceeds from sales of excess SO<sub>2</sub> allowances.
87. **Oklahoma Gas & Electric Co., 2007 (Cause No. PUD 07-012)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E’s application seeking pre-approval to construct the Red Rock coal plant to address the Company’s proposed rider recovery mechanism.
88. **Oklahoma Natural Gas Co., 2007 (Cause No. PUD 07-335)** – Participated as an expert witness on behalf of the OIEC before the OCC in ONG’s application proposing alternative cost recovery for the Company’s ongoing capital expenditures through the proposed Capital Investment Mechanism Rider (“CIM Rider”). Sponsored testimony to address ONG’s proposal.
89. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company’s use of debt equivalency in the competitive bidding process for new resources.
90. **Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
91. **Nevada Power Company, 2007, (Docket No. 07-01022)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company’s deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.
92. **Nevada Power Company, 2006, (Docket No. 06-11022)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
93. **Southwestern Public Service Co., 2006 (PUCT Docket No. 37766)** – Participated as an expert witness on behalf of the Alliance of Xcel Municipalities (“AXM”) in the SPS general rate case application. Provided testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsored the Accounting Exhibits on behalf of AXM.
94. **Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676)** – Participated as an expert witness in the Atmos Mid-Tex general rate case application on behalf of the Atmos Texas Municipalities (“ATM”). Provided written and oral testimony before the Railroad Commission of Texas regarding the revenue requirements of Mid-Tex including various rate base, operating expense, depreciation and tax issues. Sponsored the Accounting Exhibits for ATM.
95. **Nevada Power Company, 2006 (Docket No. 06-06007)** – Participated as an expert witness on behalf of the MGM MIRAGE in the Sinatra Substation Electric Line Extension and Service Contract case. Provided both written and oral testimony before the Nevada Public Utility Commission to provide the Commission with information as to why the application is consistent with the line extension requirements of Rule 9 and why the cost recovery proposals set forth in the application

provide a least cost approach to adding necessary new capacity in the Las Vegas strip area.

96. **Public Service Co. of Oklahoma, 2006 (Cause No. PUD 05-00516)** - Participated as an expert witness on behalf of the OIEC to review PSO's application for a "used and useful" determination of its proposed peaking facility.
97. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 06-00041)** – Participated as an expert witness on behalf of the OIEC in OG&E's application to propose an incentive sharing mechanism for SO<sub>2</sub> allowance proceeds.
98. **Chermac Energy Corporation, 2006 (Cause No. PUD 05-00059 and 05-00177)** – Participated as an expert witness on behalf of the OIEC in Chermac's PURPA application. Sponsored written responsive and rebuttal testimony to address various rate design issues arising under the application.
99. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 05-00140)** – Participated as an expert witness on behalf of the OIEC in OG&E's 2003 and 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, its transactions with affiliates, and the prices paid for natural gas, coal and purchased power.
100. **Nevada Power Company, 2006, (Docket No. 06-01016)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written testimony in NPC's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.
101. **Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151)** – Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application. Sponsored both written and oral testimony before the OCC to address various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates.
102. **Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610)** – Participated as an expert witness on behalf of the Attorney General of Oklahoma. Sponsored written and oral testimony to address numerous rate base, operating expense and depreciation issues for the purpose of setting prospective cost-of-service based rates.
103. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participated as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.'s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.'s proposed increase in depreciation rates associated with increased negative salvage value calculations.
104. **Public Service Co. of Oklahoma, 2004 (Cause No. PUD 02-0754)** – Participated as an expert witness on behalf of the OIEC. Sponsored written testimony (1) making adjustments to PSO's requested recovery of an ICR programming error, (2) correcting errors in the allocation of trading margins on off-system sales of electricity from AEP East to West and among the AEP West utilities and (3) recommending an annual rather than a quarterly change in the FAC rates.
105. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564)** - Participated as an expert witness on behalf of the OIEC to provide the OCC with direction in setting an avoided cost for the PowerSmith Cogeneration project under PURPA requirements. Provided both written and oral testimony on the provisions of the proposed contract under PURPA:
106. **Electric Utility Rules for Affiliate Transactions, 2004 (Cause No. RM 03-0003)** – Participated as a

consultant on behalf of the OIEC to draft comments to assist the OCC in developing rules for affiliate transactions. Assisted in drafting the proposed rules. Successful in having the Lower of Cost or Market rule adopted for affiliate transactions in Oklahoma.

107. **Nevada Power Company, 2003, (Docket No. 03-10001)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
108. **Nevada Power Company, 2003, (Docket No. 03-11019)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.
109. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
110. **Oklahoma Gas & Electric Co., 2003 (Cause No. PUD 03-0226)** – Participated as an expert witness on behalf of the OIEC. Provided both written and oral testimony before the OCC to determine the appropriate level to include in rates for natural gas transportation and storage services acquired from an affiliated company.
111. **Nevada Power Company, 2003 (Docket No. 02-5003-5007)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony to calculate the appropriate exit fee in MGM Mirage's 661 Application to leave the system.
112. **McCarthy Family Farms, 2003** – Participated as a consultant to assist McCarthy Family Farms in converting a biomass and biosolids composting process into a renewable energy power producing business in California.
113. **Bice v. Petro Hunt, 2003 (ND, Supreme Court No. 20030306)** - Participated as an expert witness in a class certification proceeding to provide cost-of-service calculations for royalty valuation deductions for natural gas gathering, dehydration, compression, treatment and processing fees in North Dakota.
114. **Nevada Power Company, 2003 (Docket No. 03-11019)** - Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power. Provided written and oral testimony on the reasonableness of the cost allocations to the utility's various customer classes.
115. **Wind River Reservation, 2003 (Fed. Claims Ct. No. 458-79L, 459-79L)** – Participated as a consulting expert on behalf of the Shoshone and Arapaho Tribes to provide cost-of-service calculations for royalty valuation deductions for gathering, dehydration, treatment and compression of natural gas and the reasonableness of deductions for gas transportation.
116. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455)** – Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored written and oral testimony on numerous revenue requirement issues including rate base, operating expense and rate design issues to establish prospective cost-of-service based rates.

117. **Nevada Power Company, 2002 (Docket No. 02-11021)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power and to make recommendations with respect to rate design.
118. **Nevada Power Company, 2002 (Docket No. 01-11029)** - Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power included in the Company's \$928 million deferred energy balances.
119. **Nevada Power Company, 2002 (Docket No. 01-10001)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
120. **Chesapeake v. Kinder Morgan, 2001 (CIV-00-397L)** - Participated as an expert witness on behalf of Chesapeake Energy in a gas gathering dispute. Sponsored testimony to calculate and support a reasonable rate on the gas gathering system. Performed necessary calculations to determine appropriate levels of operating expense, depreciation and cost of capital to include in a reasonable gathering charge and developed an appropriate rate design to recover these costs.
121. **Southern Union Gas Company, 2001** - Participated as a consultant to the City of El Paso in its review of SUG's gas purchasing practices, gas storage position, and potential use of financial hedging instruments and ratemaking incentives to devise strategies to help shelter customers from the risk of high commodity price spikes during the winter months.
122. **Nevada Power Company, 2001** - Participated as an expert witness on behalf of the MGM-Mirage, Park Place and Mandalay Bay Group before the Nevada Public Utility Commission to review NPC's Comprehensive Energy Plan (CEP) for the State of Nevada and make recommendations regarding the appropriate level of additional costs to include in rates for the Company's prospective power costs associated with natural gas and gas transportation, coal and coal transportation and purchased power.
123. **Bridenstine v. Kaiser-Francis Oil Co. et al., 2001 (CJ-95-54)** - Participated as an expert witness on behalf of royalty owner plaintiffs in a valuation dispute regarding gathering, dehydration, metering, compression, and marketing costs. Provided cost-of-service calculations to determine the reasonableness of the gathering rate charged to the royalty interest. Also provided calculations as to the average price available in the field based upon a study of royalty payments received on other wells in the area.
124. **Klatt v. Hunt et al., 2000 (ND)** - Participated as an expert witness and filed report in United States District Court for the District of North Dakota in a natural gas gathering contract dispute to calculate charges and allocations for processing, sour gas compression, treatment, overhead, depreciation expense, use of residue gas, purchase price allocations, and risk capital.
125. **Oklahoma Gas and Electric Co., 2000 (Cause No. PUD 00-0020)** - Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Provided a list of criteria with which to measure a utility's proposal for alternative ratemaking. Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.
126. **Oklahoma Gas and Electric Co., 1999** - Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Performance Based Ratemaking (PBR)

proposal including analysis of the Company's regulated return on equity, fluctuations in the capital investment and operating expense accounts of the Company and the impact that various rate base, operating expense and cost of capital adjustments would have on the Company's proposal.

127. **Nevada Power Company, 1999 (Docket No. 99-7035)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony addressing the appropriate ratemaking treatment of the Company's deferred energy balances, prospective power costs for natural gas, coal and purchased power and deferred capacity payments for purchased power.
128. **Nevada Power Company, 1999 (Docket No. 99-4005)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to unbundle the utility services of the NPC and to establish the appropriate cost-of-service allocations and rate design for the utility in Nevada's new competitive electric utility industry.
129. **Nevada Power Company, 1999 (Docket No. 99-4005)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to establish the cost-of-service revenue requirement of the Company.
130. **Nevada Power/Sierra Pacific Merger, 1998 (Docket No. 98-7023)** - Participated as an expert witness on behalf of the Mirage and MGM Grand before the Nevada PUC. Sponsored written and oral testimony to establish (1) appropriate conditions on the merger (2) the proper sequence of regulatory events to unbundle utility services and deregulate the electric utility industry in Nevada (3) the proper accounting treatment of the acquisition premium and the gain on divestiture of generation assets. The recommendations regarding conditions on the merger, the sequence of regulatory events to unbundle and deregulate, and the accounting treatment of the acquisition premium were specifically adopted in the Commission's final order.
131. **Oklahoma Natural Gas Company, 1998 (Cause No. PUD 98-0177)** - Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of Transok, LLC to establish the cost of ONG's unbundled upstream gas services. Substantially all of the cost-of-service recommendations to unbundle ONG's gas services were adopted in the Commission's interim order.
132. **Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214)** - Audited both rate base investment and operating revenue and expense to determine the Company's revenue requirement and cost-of-service. Sponsored written testimony before the OCC on behalf of the OIEC.
133. **Oklahoma Natural Gas /Western Resources Merger, 1997 (Cause No. PUD 97-0106)** - Sponsored testimony on behalf of the OIEC regarding the appropriate accounting treatment of acquisition premiums resulting from the purchase of regulated assets.
134. **Oklahoma Gas and Electric Co., 1996 (Cause No. PUD 96-0116)** - Audited both rate base investment and operating income. Sponsored testimony on behalf of the OIEC for the purpose of determining the Company's revenue requirement and cost-of-service allocations.
135. **Oklahoma Corporation Commission, 1996** - Provided technical assistance to Commissioner Anthony's office in analyzing gas contracts and related legal proceedings involving ONG and certain of its gas supply contracts. Assignment included comparison of pricing terms of subject gas contracts to portfolio of gas contracts and other data obtained through annual fuel audits analyzing ONG's gas purchasing practices.

136. **Tenkiller Water Company, 1996** - Provided technical assistance to the Attorney General of Oklahoma in his review of the Company's regulated cost-of-service for the purpose of setting prospective utility rates.
137. **Arkansas Oklahoma Gas Company, 1995 (Cause No. PUD 95-0134)** - Sponsored written and oral testimony before the OCC on behalf of the Attorney General of Oklahoma regarding the price of natural gas on AOG's system and the impact of AOG's proposed cost of gas allocations and gas transportation rates and tariffs on AOG's various customer classes.
138. **Enogex, Inc., 1995 (FERC 95-10-000)** - Analyzed Enogex's application before the FERC to increase gas transportation rates for the Oklahoma Independent Petroleum Association and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.
139. **Oklahoma Natural Gas Company, 1995 (Cause No. PUD 94-0477)** - Analyzed a portfolio of ONG's gas purchase contracts in the Company's Payment-In-Kind (PIC) gas purchase program and made recommendations to the OCC Staff on behalf of Terra Nitrogen, Inc. regarding the inappropriate profits made by ONG on the sale of the gas commodity through the PIC program pricing formula. Also analyzed the price of gas on ONG's system, ONG's cost-of-service based rates, and certain class cross-subsidizations in ONG's existing rate design.
140. **Arkansas Louisiana Gas Company, 1994 (Cause No. PUD 94-0354)** - Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of the other auditors on the case. Sponsored cost-of-service testimony on cash working capital and developed policy recommendations on post test year adjustments.
141. **Empire District Electric Company, 1994 (Cause No. PUD 94-0343)** - Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of other auditors. Sponsored cost-of-service testimony on rate base investment areas including cash working capital.
142. **Oklahoma Natural Gas Company, 1992 through 1993 (Cause No. PUD 92-1190)** - Planned and supervised the rate case audit of ONG for the OCC Staff. Reviewed all workpapers and testimony of the other auditors on the case. Sponsored written and oral testimony on numerous cost-of-service adjustments. Analyzed ONG's gas supply contracts under the Company's PIC program.
143. **Oklahoma Gas and Electric Company, 1991 through 1992 (Cause No. PUD 91-1055)** - Audited the rate base, operating revenue and operating expense accounts of OG&E on behalf of the OCC Staff. Sponsored written and oral testimony on numerous revenue requirement adjustments to establish the appropriate level of costs to include for the purpose of setting prospective rates.

## OIEC REVENUE REQUIREMENT CALCULATIONS

PSO Rate Case Cause No. PUD 201700151  
Test Year Ended December 31, 2016

Ln.	Descriptions	Witness	Ref.	Rate Base Items	ROR W/Tax	Total Company Impact
1	<b>PSO Requested Rate Increase In Rate Case</b>		Sch B-01			\$ 169,667,526
2						
3	<b>Rate Base</b>		Sch B-01	\$ 2,527,472,526		
4	Adjust Plant Investment to 6-Month Level	Garrett	MG2.1	\$ 69,196,225	10.318%	7,139,390
5	Adjust Accum Depr to 6-Month Level	Garrett	MG2.1	(32,673,645)	10.318%	(3,371,136)
6	Adjust Materials and Supplies to 6-Month Level	Garrett	MG2.1	(6,737,892)	10.318%	(695,189)
7	Adjust Customer Deposits to 6-Month Level	Garrett	MG2.1	(986,714)	10.318%	(101,805)
8	Adjust Regulatory Assets to 6-Month Level	Garrett	MG2.1	(7,260,127)	10.318%	(749,071)
9	Adjust Regulatory Liabilities to 6-Month Level	Garrett	MG2.1	84,856	10.318%	8,755
10	Adjust ADFIT to 6-Month Level	Garrett	MG2.1	(39,349,920)	10.318%	(4,059,967)
11	Remove Unsupported Prepaid Pension Balance	Garrett	MG2.2	(36,508,316)	10.318%	(3,766,782)
12	Remove Northeastern 4 from Rate Base	Garrett	MG2.7	(50,736,636)	10.318%	(5,234,803)
13	Remove Disallowed Incentives from Rate Base	Garrett	MG2.4	(37,645,259)	10.318%	(3,884,087)
14	<b>Total Rate Base Adjustments</b>			\$ (142,617,427)		\$ (14,714,695)
15						
16	<b>Cost of Capital</b>					
17	PSO Requested Pre-Tax Rate of Return		MG2.12		10.318%	
18	OIEC Reduction to Pre-Tax Rate of Return	Parcell	9.000%	\$ 2,384,855,099	-0.787%	\$ (18,759,270)
19	OIEC Recommended Pre-Tax Rate of Return				9.531%	
20						
21	<b>Operating Expense Adjustments</b>			470,000,000	44.795.700	
22	Reverse PSO Post-Test Year Payroll Increase	Garrett	MG2.3			(2,726,115)
23	Reverse AEPSC Post-Test Year Payroll Increase	Garrett	MG2.3			(2,773,687)
24	Remove 75% of Annual Incentive Plan	Garrett	MG2.4			(6,824,159)
25	Remove 100% of Executive Incentive Plan	Garrett	MG2.4			(3,106,766)
26	Remove Incentive Labor Attendant Costs	Garrett	MG2.4			(756,117)
27	Remove PSO & AEPSC SERP Retirement Costs	Garrett	MG2.5			(349,862)
28	Adjust Rate Case Expenses	Garrett	MG2.6			(432,892)
29	Reverse PSO Storm Expense Increase	Garrett	MG2.8			(8,263,753)
30	Reverse Production O&M Increase	Norwood	MG2.9			(7,790,317)
31	Reverse SPP Expense Increases	Norwood	MG2.10			(17,635,706)
32	<b>Total Operating Revenue &amp; Expense Adjustments</b>					\$ (50,659,374)
33						
34	<b>Depreciation Expense Adjustments</b>					
35	Adjust Depreciation Rates	D. Garrett	MG2.11			\$ (29,061,596)
36	Remove Northeastern 4 Depreciation	M. Garrett	MG2.7			\$ (4,141,552)
37	<b>Total Depreciation Adjustments</b>					\$ (33,203,148)
38						
39	<b>Total Impact of OIEC Adjustments</b>					\$ (117,336,487)
40						
41	<b>Rate Increase after OIEC Adjustments</b>					<b>\$ 52,331,039</b>
42						
43	<b>Riders Rolled into Base Rates</b>					\$ (24,000,000)
44						
45	<b>Effective Net Increase after OIEC Adjustments</b>					<b>\$ 28,331,039</b>