

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE)
COMPANY OF OKLAHOMA, AN)
OKLAHOMA CORPORATION, FOR AN) CAUSE NO. PUD 201300217
ADJUSTMENT IN ITS RATES, AND)
CHARGES FOR ELECTRIC SERVICE)
IN THE STATE OF OKLAHOMA)

RESPONSIVE TESTIMONY
OF
MARK E. GARRETT

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

April 23, 2014

**Prepared Responsive Testimony of Mark E. Garrett
April 23, 2014
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 50 Penn Place, Suite 410, 1900 NW
3 Expressway, Oklahoma City, Oklahoma 73118.

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: WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND
10 AND YOUR PROFESSIONAL EXPERIENCE RELATED TO UTILITY
11 REGULATION?**

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

1 Dallas, I managed the Company's accounting function, including general ledger,
2 accounts payable, financial reporting, audits, tax returns, budgets, projections, and
3 supervision of accounting personnel. In utility regulation, I served as an auditor in the
4 Public Utility Division of the Oklahoma Corporation Commission from 1991 to 1995.
5 In that position, I managed the audits of major gas and electric utility companies in
6 Oklahoma. Since leaving the Commission, I have worked on various rate cases and
7 other regulatory proceedings on behalf of industrial interveners, gas pipelines and the
8 Attorney General of Oklahoma.

9
10 **Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THIS COMMISSION**
11 **AND IN OTHER PROCEEDINGS DEALING WITH COST-OF-SERVICE AND**
12 **OTHER RATEMAKING ISSUES?**

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

15
16 **Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?**

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

18
19 **Q: WHO IS OIEC?**

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

1

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

3 A: OIEC is an association which represents the interests of industrials and other large
4 energy consumers. Many industries in Oklahoma purchase substantial quantities of
5 electric power which are important to their operations. Electric power costs can
6 constitute a significant percentage of industrial operating costs. These electric power
7 supplies are generally purchased from utilities pursuant to standard tariffs filed at the
8 Commission. Industries served by PSO operate in highly competitive business
9 environments and, thus, are interested in the Commission determining rates for PSO that
10 achieve reliable power supply at the lowest and most reasonable costs possible under the
11 circumstances.

12

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

14 A: The purpose of my testimony is to address various revenue requirement issues identified
15 in PSO’s rate case application and to provide the Commission with recommendations for
16 the resolution of these issues. I also sponsor *Exhibit MG-2* included with this testimony
17 where the overall impact of OIEC’s recommendations is set forth. In total, OIEC’s
18 recommendations result in a rate decrease of \$22,196,431 as shown below:

19	Rate Increase Proposed by PSO	\$ 37,305,012
20	OIEC Adjustments	<u>\$(59,501,443)</u>
21	Decrease Proposed by OIEC	<u>\$(22,196,431)</u>

II. RATE BASE ADJUSTMENTS

II. A. PLANT AND ACCUMULATED DEPRECIATION- 6 MONTH POST TEST YEAR ADJUSTMENT

1 **Q. ARE YOU PROPOSING ADJUSTMENTS TO THE COMPANY'S PRO FORMA**
2 **PLANT IN SERVICE AND ACCUMULATED DEPRECIATION BALANCES?**

3 A. Yes. My adjustment updates the Plant in Service and Accumulated Depreciation
4 accounts through January 31, 2014. In Oklahoma, the Commission is required by law
5 (Title 17 § 284) to give effect to known and measurable changes that occur within six
6 months of test year end. In this application, the six month cut-off period for post test
7 year adjustments is January 31, 2014.

8
9 **Q: HOW IS YOUR ADJUSTMENT TO REFLECT ACTUAL INVESTMENT**
10 **LEVELS AT JANUARY 31, 2014 CALCULATED?**

11 A: In general, the adjustment is calculated by comparing the Company's requested level of
12 Plant in Service and Accumulated Depreciation to the actual balances in these accounts
13 at January 31, 2014. The Company's requested level for plant investment includes
14 actual Plant in Service balances at test year end, plus the cost of construction projects
15 expected to be completed and in service within six months after test year end. My
16 adjustment picks up the actual plant balances at January 31, 2014. Thus, all plant
17 construction actually completed and in service within six months of test year end is
18 properly included in rate base. Also, all offsetting decreases in the plant investment

1 levels – in effect, all changes in the Accumulated Depreciation accounts – are recognized
2 as well.

3
4 **Q: HAS THE COMMISSION PREVIOUSLY ACCEPTED THIS APPROACH?**

5 A: Yes. In ONG’s 2005 rate case, Cause No. PUD 200400610, the first rate case heard by
6 the Commission after passage of the 6-month rule in Title 17 § 284, the ALJ adopted this
7 approach, and the Commission accepted and approved the ALJ’s recommendation. In
8 that proceeding, after a hearing on the merits, the ALJ updated ONG’s Plant in Service
9 and Accumulated Depreciation balances through the six month period following test year
10 end. Projects still in the Construction Work in Progress (“CWIP”) accounts at that time
11 were specifically excluded. Also, in OG&E’s 2005 rate case, PUD 200500151, the
12 Commission again updated the Plant and Accumulated Depreciation balances to six
13 months after test year end and appropriately excluded CWIP on the books at that time.
14 Also, in PSO’s last two litigated rate cases, the Commission followed this approach.¹

15
16 **Q: HAVE YOU REVIEWED PSO’S PROPOSED ADJUSTMENT TO INCLUDE**
17 **CONSTRUCTION WORK IN PROGRESS (CWIP) AT TEST YEAR END IN**
18 **UTILITY RATE BASE?**

19 A: Yes. The Company proposes to increase plant levels at test year end for CWIP projects
20 that are expected to be completed during the 6-month post test year period. However, a
21 CWIP adjustment, as proposed by the Company, is not necessary when the Plant in

¹ See Cause Nos. PUD 200600285 and PUD 200800144.

1 Service and Accumulated Depreciation accounts are updated to the 6-month post-test-
2 year cutoff date. By updating the plant accounts to the January 31, 2014 cutoff, all
3 CWIP projects completed by that time are included in the adjustment. When the
4 Commission adopted this approach in prior ONG, OG&E and PSO cases, the
5 Commission updated the Plant in Service balances and the Accumulated Depreciation
6 balances to 6-month cutoff and appropriately excluded CWIP on the books at that time.
7 This treatment has the effect of including in rate base all CWIP projects actually
8 complete and in service within the 6-month post test year period.

9
10 **Q: HOW IS CWIP GENERALLY TREATED FOR RATEMAKING PURPOSES**
11 **WHEN THE TEST YEAR IS NOT UPDATED?**

12 A: Generally, CWIP is excluded from rate base and instead permitted to earn an allowance
13 for funds used during construction (“AFUDC”) return until such time as these projects
14 are completed and transferred to the Plant in Service accounts. This generally accepted
15 ratemaking treatment preserves the integrity of the historical test year without causing
16 economic harm to the Company.

17
18 **Q: WHY IS THIS THE GENERALLY ACCEPTED TREATMENT OF CWIP?**

19 A: Traditional ratemaking principles exclude CWIP from rate base because plant under
20 construction is not *used and useful* for providing electric service to utility customers
21 currently on the system. However, in order to allow investors an opportunity to earn a
22 return on their invested capital, CWIP accrues an AFUDC return while the projects are

1 under construction. When construction is completed and the facilities are dedicated to
2 utility service, the invested capital along with its accrued return is transferred to rate
3 base.

4
5 **Q: ARE THERE OCCASIONS WHEN REGULATORS, APPLYING SOUND**
6 **RATEMAKING PRINCIPLES, MAY ALLOW SOME PORTION OF CWIP IN**
7 **RATE BASE?**

8 A: Yes, on occasion, regulators may include some level of CWIP in rate base when the
9 completion date of a project is imminent and the facilities are certain to serve customers
10 shortly after test year end. In these instances, however, the utility is generally required
11 to show that significant financial harm will result if CWIP is not included. However, if
12 projects completed after test year end are included in pro forma rate base, there are
13 several other offsetting adjustments that must also be made.

14
15 **Q: WHAT OTHER RATEMAKING ADJUSTMENTS MUST BE MADE WHEN**
16 **SOME PORTION OF CWIP IS INCLUDED IN RATE BASE UNDER A**
17 **THEORY THAT THE PROJECTS WILL BE COMPLETED AND**
18 **OPERATIONAL SHORTLY AFTER TEST YEAR END?**

19 A: On those occasions when CWIP is included in rate base under a theory that the projects
20 will be completed and placed in service within a short period after test year end, revenue
21 levels should also be increased to recognize incremental revenue on the date the new
22 facilities are placed in service. Rate base also should be reduced by the amount of

1 accumulated depreciation that has accrued up to that date. The accumulated deferred
2 income tax accounts should be updated as well. While it is generally better not to go
3 beyond the test year to pick up an insular set of post test year adjustments such as these,
4 it is never appropriate to go beyond the test year to recognize a single adjustment to
5 increase rates, such as CWIP, without recognizing those related adjustments that
6 decrease rates as well, such as higher levels of revenue and accumulated depreciation.

7 However, when a post-test-year period update is used, none of these additional
8 adjustments – including the CWIP adjustment – are necessary, because all of the
9 accounts, including the plant balances, accumulated depreciation and deferred tax
10 accounts are updated to the cutoff date. As presented, a request that the Commission
11 look beyond the test year to increase rates for CWIP projects in a piecemeal fashion
12 without considering mitigating increases in the depreciation reserve and deferred tax
13 accounts that occur over the same period of time is inappropriate. If the Commission
14 goes beyond the test year to include increases in rate base for capital expenditures, it
15 must also consider recoveries of capital through depreciation over the same period and
16 the higher levels of revenue as well. In Oklahoma, the better approach is to update all
17 the plant, accumulated depreciation, revenue and deferred tax accounts to the end of the
18 6-month update period, as the Commission has done in every major utility rate case since
19 the 6-month statute was enacted.

20
21 **Q: IS YOUR PROPOSED TREATMENT CONSISTENT WITH BOTH**
22 **OKLAHOMA LAW AND SOUND RATEMAKING PRINCIPLES?**

1 A: Yes. The proposed treatment satisfies the statutory requirement to give effect to known
2 and measurable changes occurring within six months of test year end because both the
3 Plant in Service balances and the Accumulated Depreciation balances are updated to the
4 end of the 6-month post test year period.

5
6 **Q: DID YOU MAKE ANY OTHER ADJUSTMENTS TO PSO'S PLANT IN**
7 **SERVICE AND ACCUMULATED DEPRECIATION BALANCES AS OF**
8 **JANUARY 31, 2014?**

9 A: Yes. It was necessary to make three adjustments to PSO's Plant in Service as of January
10 31, 2014. These adjustments are related to the AMI meter costs and related Intangible
11 Plant associated with AMI Meters. In its Application, PSO removed these costs from
12 Plant in Service balance and requested that these costs be recovered through a rider
13 mechanism. In my rate design testimony, I recommend that PSO's requested rider
14 recovery mechanism for AMI not be approved. Although I do not support using a rider
15 mechanism to recover these costs, I do recommend that AMI costs incurred as of January
16 31, 2014 related to AMI Meters and AMI Intangible Plant be included in rate base.
17 Therefore, I have made an adjustment to include these costs in PSO's Plant in Service as
18 of January 31, 2014. Similarly, PSO removed from its Accumulated Depreciation
19 account the corresponding accumulated depreciation associated with AMI Meters. I
20 have reinstated these amounts to the January 31, 2014 balances. These adjustments are
21 reflected in Table 1 set forth below.

22

1 **Q: PLEASE SUMMARIZE THE ADJUSTMENTS TO PRO FORMA RATE BASE**
2 **NEEDED TO REFLECT ACTUAL NET INVESTMENT LEVELS AT JANUARY**
3 **31, 2014.**

4 **A:** OIEC's adjustments to the Company's pro forma rate base are set forth below. The
5 detailed calculations reflecting PSO's actual investment levels at January 31, 2014 are
6 set forth in *Exhibit MG-2.1* attached to this testimony.

Table 1: OIEC Adjustments to Plant and Accumulated Depreciation				
	Description	OIEC Adjusted Plant Balances 1/31/2014	PSO Pro Forma Plant (Includes CWIP)	OIEC Adjustment
1	PSO's Plant in Service 1/31/14	\$4,298,561,651		
2	Add: PSO Intangibles Adjustment	\$5,166,456		
3	Add: AMI Meter Adjustment	\$10,853,807		
4	Total Adjusted Plant in Service	\$4,314,581,914	\$ 4,228,153,805	\$86,428,109
5	Accumulated Depreciation	\$(1,610,610,731)		
6	AMI Related Accumulated Depreciation	\$(2,220,725)		
7	Total Accumulated Depreciation 1/31/14	\$(1,612,831,456)	\$(1,596,714,353)	\$(16,117,103)
8	Net Plant in Service	\$2,701,750,458	\$2,631,439,452	\$71,663,965

II. B. ACCUMULATED DEFERRED INCOME TAXES

1 **Q: WHAT ADJUSTMENT ARE YOU PROPOSING FOR ACCUMULATED**
2 **DEFERRED INCOME TAXES?**

3 A: This adjustment updates the Company's Accumulated Deferred Income Tax ("ADIT")
4 balances to the January 31, 2014 levels. This adjustment is necessary to give effect to
5 the known and measurable increase in the deferred tax balances that occurred within six
6 months of test year end. When additions to the investment levels in Plant in Service are
7 recognized through the 6-month period following test year end, as requested by the
8 Company in this cause, offsetting decreases in the investment levels related to Plant in
9 Service such as Accumulated Depreciation and Accumulated Deferred Income Tax must
10 also be recognized. This adjustment has been consistently recognized and accepted by
11 the Commission in rate case proceedings after the 6-month rule was enacted.

12
13 **Q: WHAT ADJUSTMENTS ARE NECESSARY TO UPDATE THE**
14 **ACCUMULATED DEFERRED INCOME TAX BALANCES?**

15 A: An adjustment is necessary to update the ADIT account to January 31, 2014. In addition
16 the ADIT account balance must be adjusted to add back the ADIT associated with both
17 the AMI Meter costs and the AMI Intangible Plant costs which have been reinstated in
18 Plant in Service for purposes of the OIEC calculations. The necessary adjustments are
19 set forth in Table below and can be seen at *Exhibit MG-2.2* attached to this testimony.

Table 2: OIEC Adjustments to ADIT Account Balance		
1	Accumulated Deferred Income Tax at January 31, 2014	\$ (842,492,288)
2	Add: Intangibles ADIT at January 31, 2014	\$ (1,228,324)
3	Add: AMI Meter ADIT at January 31, 2014	\$ (865,450)
4	Total Adjusted Plant in Service at January 31, 2014	\$ (844,586,062)
5	PSO Pro Forma Plant in Service	\$ (824,276,775)
6	OIEC Adjustment to ADIT	\$ (20,309,287)

II. C. OTHER RATE BASE ADJUSTMENTS

1 **Q: WHAT OTHER ADJUSTMENTS HAVE YOU MADE TO THE COMPANY'S**
2 **PRO FORMA RATE BASE?**

3 A: I have updated the fuel inventory level to reflect the actual fuel inventory level at
4 January 31, 2014, consistent with the 6-month rule in Oklahoma. The Company
5 proposed using 13-month averages at test year end in pro forma rate base for these
6 accounts. I am proposing to use the actual level at January 31, 2014, because these
7 inventory levels decreased after the end of the test year and did not fluctuate much
8 during the 6-month post test year period.

9 I have also updated the prepayment balance to reflect the actual level at January
10 31, 2014, consistent with the 6-month rule in Oklahoma. The Company proposed using
11 a 13-month average at test year end. I am proposing that the actual level at January 31,
12 2014 be used, as prepayment levels decreased after test year end and have remained at
13 this lower level.

1 **Q: ARE THERE OTHER RATE BASE ADJUSTMENTS?**

2 A: Yes. The Company included a regulatory asset for the July 2013 storm costs in the
3 amount of \$10,000,000. The Company is seeking a four-year amortization of these costs
4 in base rates. Although I am not opposing the base rate recovery of these costs at this
5 time, I do not believe the deferred costs should earn a return while they are being
6 recovered. The utility has effectively shed all of its rate-recovery risk associated with
7 storm losses through the deferred accounting treatment of these costs. It should not also
8 be allowed to earn a profit return on these costs during the recovery process.

9
10 **Q: WHAT ADJUSTMENTS ARE NEEDED TO REFLECT THE FUEL**
11 **INVENTORY LEVEL AT JANUARY 31, 2014 AND THE STORM**
12 **REGULATORY ASSET REMOVAL FROM RATE BASE?**

13 A: My adjustments are shown in the table below. The calculations supporting these
14 adjustments are set forth in more detail at *Exhibit MG-2.3*.

Table 3: OIEC Other Rate Base Adjustments				
	Description	Fuel Inventory	Prepayments	July 2013 Storm
1	PSO's Pro Forma Fuel Inventory	\$ 19,474,443	\$111,004,957	\$ 10,000,000
2	PSO's Adjustment for Eliminated Oil Inventory	\$ (1,381,154)		
3	Total PSO Pro Forma Fuel Inventory	\$ 18,093,289		
4	Actual Fuel Inventory Level at January 31, 2014	\$ 15,734,288	\$105,373,187	
5	OIEC Adjustment to Fuel Inventory Level /Storm	\$ (2,359,001)	\$(5,631,770)	\$(10,000,000)

II. D. PREPAID PENSION ASSET

1 **Q: WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE COMPANY'S**
2 **PREPAID PENSION BALANCE IN PRO FORMA RATE BASE?**

3 A: I am proposing to reduce PSO's rate base by the balance in this account and increase
4 operating expense by an amount equivalent to the "expected return" on the prepaid
5 pension asset balance. This is the amount by which ratepayers benefit from these excess
6 contributions. AEP's *expected return* on pension contributions is 6.5%.² This is the
7 amount by which the excess contributions reduce Net Periodic Pension Costs, the
8 amount included in rates. In effect, the net benefit to ratepayers from excess
9 contributions is 6.5%. Thus, I am proposing that ratepayers pay a return on these costs
10 that is no greater than the benefit they receive.

11
12 **Q: WHAT DOES THE BALANCE IN THE PREPAID PENSION ACCOUNT**
13 **REPRESENT?**

14 A: In general terms, the balance in this account is the accumulated difference between (1)
15 the Statement of Financial Accounting Standards No. 87 ("SFAS 87") calculated pension
16 costs each year – the amount included in rates – and (2) the actual contributions made by
17 the Company to the pension fund. When there is a debit balance in the account, as is the
18 case here, the Company has been contributing more to the fund than its SFAS 87
19 calculated cost levels.

20

² See Exhibit RWH-2.

1 **Q: ARE THESE CONTRIBUTIONS MANDATORY?**

2 A: No, PSO's contributions in excess of the SFAS 87 cost levels were generally
3 discretionary payments. These payments, however, do generally tend to increase the
4 Company's pension asset, which tends to decrease future funding needed to cover the
5 pension liability.

6
7 **Q: WHY ARE YOU RECOMMENDING A RETURN EQUAL TO THE *EXPECTED***
8 ***RETURN ON CONTRIBUTIONS* RATHER THAN A FULL RATE BASE**
9 **RETURN ON THIS BALANCE?**

10 A: I am recommending a return equal to the *expected return* because this is the amount by
11 which ratepayers benefit from these contributions. Also, a higher full rate base return
12 includes a substantial profit component that the lower *expected* return does not include.
13 Since the contributions to the pension fund above the SFAS 87 expense levels have been
14 discretionary contributions, ratepayers should not be required to pay an amount that is
15 greater than the benefit they receive from these contributions, and the Company should
16 not be allowed to earn a profit on the excess discretionary contributions it makes to the
17 fund.

18
19 **Q: HAS THE TREATMENT YOU ARE PROPOSING FOR PREPAID PENSIONS**
20 **BEEN ACCEPTED BY THIS COMMISSION IN THE PAST?**

21 A: Yes. In ONG's 1992 rate case, Cause No. PUD 1991001190, the Commission allowed a
22 cost of debt return on ONG's deferred pension balance. More recently, in Cause No.

1 PUD 200500151, the Commission removed OG&E's prepaid pension balance in the
2 amount of \$67.1 million from rate base and provided a cost of money return on the
3 balance. Likewise, in PSO's last two rate cases, Cause Nos. PUD 200600285 and PUD
4 200800144 the Commission removed the Company's prepaid pensions from rate base
5 and allowed a debt return on the balance. In PSO's last litigated rate case, Cause No.
6 PUD 200800144, the Company appealed the Commission's treatment of the Company's
7 prepaid pension costs to the Oklahoma Supreme Court. The court upheld the
8 Commission's treatment of these costs.

9
10 **Q: WHAT ADJUSTMENTS ARE YOU PROPOSING?**

11 A: Actually three adjustments are needed. One adjustment is needed to remove the prepaid
12 pension balance from rate base; another adjustment is needed to add back the
13 accumulated deferred income taxes (ADIT) balance associated with prepaid pension
14 costs; and, a third adjustment is needed to increase O&M expense by an amount equal to
15 the *expected* return on the prepaid balance. The necessary adjustments are set forth
16 below and can be seen at *Exhibit MG-2.4*.

Table 4: OIEC Adjustments to Prepaid Pension Account		
1	Adjustment to Remove Prepaid Pension Balance in Rate Base	(\$104,227,255)
2	Adjustment to Remove Prepaid Pensions ADIT from Rate Base	\$ 36,479,539
3	Adjust to Include <i>Expected Return</i> on Prepaid Pensions [Net Balance x Expected Return Rate: (67,747,716 x 6.50%)]	\$ 4,403,602

1 **Q: WHAT IS THE IMPACT OF THESE ADJUSTMENTS ON THE COMPANY'S**
2 **REVENUE REQUIREMENT?**

3 A: The total impact on the Company's revenue requirement is a reduction of approximately
4 \$3 million. The first two adjustments shown in Table 4 above are rate base adjustments
5 and their impact on the revenue requirement is limited to the Company's overall rate of
6 return on rate base grossed up for tax. The revenue requirement impacts of the
7 adjustments are set forth in the table below:

TABLE 5: Impact of OIEC's Pre-Paid Pension Adjustments				
Ln	Description	Adj.	ROR³	Rev. Req.
1	PSO Prepaid Pension Balance in Rate Base	(\$104,227,255)	11.206%	(\$11,679,706)
2	ADFIT associated with Prepaid Pension	\$ 36,479,539	11.206%	\$ 4,087,897
3	Provide Cost-of-Money Return	\$ 67,747,716	6.50%	\$ 4,403,602
4	Total Impact on the Revenue Requirement			\$ 3,188,207

³ OIEC's proposed rate of return grossed up for tax.

II. E. 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. The same portion of PSO's incentive payments excluded from
7 operating expense for ratemaking purposes must also be excluded from rate base. If not,
8 the Company will earn a return on, and eventually recover from ratepayers,
9 compensation associated with incentive plans the Commission has disallowed. At test
10 year end, PSO's rate base included \$41,831,824 of capitalized incentive compensation,
11 which includes \$39,048,124 of short term incentive compensation and \$2,783,700 of
12 long term incentive compensation.⁴ I propose that 50% of the capitalized short term
13 incentive payments and 100% of the capitalized long term incentive payments be
14 excluded from rate base, for a total adjustment of \$22,307,762. This treatment is
15 consistent with the Commission's prior treatment of PSO's incentive plans in the prior
16 litigated cases of PUD 200600285 and PUD 200800144.

17
18 **Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT?**

19 A: The rate base adjustment is set forth below and can be seen at *Exhibit MG-2.5*.

20 Rate Base Adjustment to Exclude Disallowed Capitalized Incentives **\$(22,307,762)**

⁴ See PSO's response to OIEC 1.1; 1.2; 1.3; 1.4 showing incentive payments capitalized from 2010 through 2013.

III. OPERATING EXPENSE ISSUES

III. A. ANNUAL INCENTIVE COMPENSATION EXPENSE

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

3 A: AEP/PSO's incentive compensation plans are formal, written plans approved by senior
4 management. In total, there are four annual incentive plans under which PSO employees
5 may be compensated, and seven plans under which AEPSC employees may be
6 compensated. These plans are described in the direct testimony and exhibits of PSO
7 witness Andrew R. Carlin. In this application, PSO seeks to include \$8.2 million in rates
8 for annual incentive expense, based upon the Company's *targeted* payout for incentive
9 expense, according to the Company.⁵

10
11 **Q: WHAT ADJUSTMENTS DO YOU PROPOSE WITH RESPECT TO THE**
12 **COMPANY'S REQUESTED LEVEL OF ANNUAL INCENTIVE**
13 **COMPENSATION EXPENSE?**

14 A: I am proposing to reduce the requested level of annual incentive expense for the portion
15 of the incentive plans related to financial performance measures. From my review of the
16 plans, it is clear that more than 50% of the *performance measures* of the annual plans are
17 tied to the Company's financial performance. As a result, I have reduced the Company's
18 requested level of annual incentive compensation of \$8,236,889 by 50%, or \$4,118,445.

⁵ See Carlin Direct Testimony at page 23. The actual amount of incentive compensation the Company paid during the test year was higher than targeted levels.

1 **Q: IS THIS CONSISTENT WITH THIS COMMISSION'S TREATMENT OF**
2 **INCENTIVE COMPENSATION?**

3 A: Yes. In PSO's last two litigated rate cases, the Commission reduced PSO's requested
4 annual incentive compensation by 50% for amounts tied to financial performance. The
5 Commission also reduced OG&E's annual incentive plan costs by 50% in OG&E's last
6 litigated rate case, PUD 200500051.

7
8 **Q: DO FINANCIAL PERFORMANCE MEASURES COMPRISE THE MOST**
9 **SIGNIFICANT COMPONENT OF PSO'S INCENTIVE COMPENSATION**
10 **PLAN?**

11 A: Yes. PSO's 2012 Annual Compensation Plans are heavily dependent on financial
12 performance measures, primarily as a result of the EPS Modifier. PSO's Incentive
13 Compensation Plan Measures and Weights⁶ sets forth the various financial and
14 nonfinancial categories the Company evaluates in its incentive compensation program.
15 However, the Company admits the funding of the incentive compensation is contingent
16 on meeting the earnings per share (EPS) targets.⁷ In other words, even though the
17 Company's performance measures include both financial and non-financial factors, the
18 actual *funding* trigger for incentive compensation is the EPS Modifier, which is directly
19 tied to the financial performance of the Company. For example, under the EPS funding
20 mechanism, regardless of how well the Company may perform in a nonfinancial
21 performance measure such as safety, if the Company's earnings per share is below the

⁶ See Carlin Direct Testimony, Exhibit ARC-7.

⁷ See Carlin Direct Testimony, p. 25, lines 3-6.

1 stated threshold, the EPS Modifier would be 0%, and thus, no portion of the incentive
2 compensation would be paid. Under this incentive compensation plan, the Company's
3 earnings level is the most significant factor in determining whether the incentive
4 compensation will be paid. According to the Company's schedules, the EPS Modifier
5 allocates incentive funding "based on the earnings produced for shareholders" and it
6 "ensures that payouts are always commensurate with AEP's EPS performance."⁸
7

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

10 A: In many jurisdictions, the cost of incentive plans which are tied to financial performance
11 measures are excluded for ratemaking purposes.⁹ When the costs associated with these
12 plans are excluded, the rationale is generally based on one or more of the following
13 reasons:

- 14 (1) **Payment is uncertain.** Often, payment of incentive compensation is conditioned
15 upon meeting some predetermined financial goal such as achieving a certain
16 increase in earnings, reaching a targeted stock price or meeting budget objectives.
17 If the predetermined goals are not met, the incentive payment is not made, or
18 payment is made at some lesser amount. Therefore, one cannot know from year
19 to year what the level of the payment may be or whether the payment will be

⁸ See Carlin Direct Testimony, Exhibit ARC-6, page 5.

⁹ 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).

1 made at all. It is generally considered inappropriate to set rates to recover a
2 tentative level of expense.¹⁰

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

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

28 **(4) The utility and its stockholders assume none of the financial risks associated**
29 **with incentive payments.** Ratepayers assume the risk that the utility will instead
30 retain the amounts collected through rates for incentive payments whenever
31 targeted increases are not reached. Employees assume the risk that the incentive
32 payments will not be made in a given year. The utility and its stockholders,
33 however, assume no risk associated with these payments. Instead, the company's
34 only responsibility is to decide who gets the money, the stockholders or the
35 employees.¹¹

¹⁰ PSO's test year experience in the prior 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.

¹¹ An example of this occurred in PSO's last 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.

1 (5) **Incentive payments based on financial performance measures should be**
2 **made out of increased earnings.** Whatever the targets or goals may be that
3 trigger an incentive payment, when the plan is based in whole or in part on
4 financial performance measures the company always obtains a financial benefit
5 from achieving these objectives. This financial benefit should provide ample
6 funds from which to make the payment. If not, the incentive plan was poorly
7 conceived in the first place. As such, employees should be compensated out of
8 the increased earnings, and not through rates.¹²

9 (6) **Incentive payments embedded in rates shelter the utility against the risk of**
10 **earnings erosion through attrition.** When utilities are allowed to embed
11 amounts for incentive payments in rates, that money is available to the utility not
12 only to pay the incentive payment when financial performance goals are met but
13 also to supplement earnings in those years when the company does not perform
14 well. In those years when financial performance measures are met, the increased
15 earnings of the company provide ample additional funds from which to make the
16 incentive payments to employees, and the incentive payment amount embedded
17 in rates is not needed. In those years when financial performance measures are
18 not met and the incentive payments are not made, the amount embedded in rates
19 for incentive payments acts as a financial hedge to shelter the poor financial
20 performance of the company.

21 Even though regulators routinely exclude financial-based incentive compensation
22 payments based on one or more of the reasons outlined above, this does not mean that
23 regulated companies will not continue to offer financial-based incentives. They do.
24 When a financial-based incentive package is properly constructed, however, there will be
25 ample increased earnings to fund these payments. Thus, ratepayers do not need to
26 subsidize incentive compensation plans designed to enhance financial performance.

¹² The fact is that AEP/PSO only makes incentive payments each year to the extent its earnings are sufficient to cover the costs of the payments. In its direct testimony the Company states: “The EPS funding measure also helps ensure that incentive compensation payments do not impair AEP financially.” (See Carlin Direct Testimony at page 24, lines 14-15).

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

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

15
16 **Q: HOW DO OTHER JURISDICTIONS TREAT INCENTIVE COMPENSATION?**

17 A: The results of an Incentive Compensation Survey of the 24 Western States taken by the
18 Garrett Group in 2007, updated in 2009 and again in 2011, shows that 19 of the 24 states
19 surveyed follow the financial-performance rule, where incentive payments associated
20 with financial performance are excluded from rates. Three states¹³ disallow incentive

¹³ Iowa, Montana and N. Dakota, disallow incentive compensation based upon other criteria.

1 pay using other criteria, and two states¹⁴ do not have stated regulation or policy for the
2 treatment of incentive compensation. None of the jurisdictions surveyed allow full
3 recovery of incentive compensation through rates as a general rule.
4

States that closely follow the Financial Performance rule

5 **Arizona** The commission deals with incentive compensation plans on a case by
6 case basis. It first compares overall compensation to the state norm, then
7 asks if the costs are prudent and reasonable. The commission leans
8 toward disallowing programs which benefit only the shareholder even if
9 total compensation is comparable to the state norm. Staff's position is that
10 unless a plan is tied to performance issues it is unnecessary for the
11 provision of service and that shareholders should pay for plans tied to
12 financial measures. In practice, the costs of annual incentive plans are
13 often shared 50/50 between ratepayers and shareholders.¹⁵

14 **Arkansas** Excludes 100% of the long-term, equity-based plans. Short-term
15 incentive plans are evaluated to determine if they are based on financial
16 or operational measures. Operational-based plans are allowed. 50% of
17 plans containing financial measures are disallowed. Any plans based
18 solely on the discretion of the company are seen as having no direct
19 benefit to ratepayers and are disallowed 100%. Settlements in recent
20 cases have upheld this treatment.¹⁶

21 **California** Incentive funding is an issue that is typically litigated. In CPUC Decision
22 00-02-046, the commission established that utilities could recover 50% of
23 the regular employee's incentive compensation costs in rates. In
24 California's latest litigated rate case, the commission decided that
25 Edison's non-executive plans and 50% of the short-term executive plans
26 would be funded in rates and that 100% of the executive long-term stock
27 plans would be disallowed.¹⁷

28 **Colorado** Regular employee programs are judged based on ratepayer verses
29 stockholder benefit ratio. Plans with metrics for goals benefiting

¹⁴ Alaska and Nebraska currently have no stated regulation or policy for the regulatory treatment of incentive compensation.

¹⁵ See e.g., APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.

¹⁶ Entergy Arkansas, 06-101-U, Order No. 10.

¹⁷ Southern California Edison (Application No. 07-11-011; Decision No. 09-03-025).

1 ratepayers but dependent on an earnings-per-share trigger are considered
2 to benefit shareholders and opposed by staff. Staff's approach is set forth
3 most recently, in 10AL-963G by staff witness Kahl. The settlement in
4 that case removed the dollar amount opposed by Kahl. All executive
5 incentives are excluded from rates and typically no longer sought in
6 company filings.

7 **Hawaii** Hawaii does not allow incentive compensation to be included in rates. In
8 Docket No. 6531 the commission agreed that bonus awards tied to
9 company income and earnings benefit stockholders, not ratepayers. The
10 commission further states, "...we believe that a utility employee,
11 especially at the executive level, should perform at an optimum level
12 without additional compensation. Ratepayers should not be burdened
13 with additional costs for expected levels of service."¹⁸

14 **Idaho** The commission's policy for evaluating incentive compensation plans
15 involves determining who benefits, the customer or the company. This
16 treatment has been refined in the recent Idaho Power rate case for plans
17 which benefit the customer but require a financial trigger to be paid. For
18 these plans the commission reduced the percentage allowed in rates. The
19 commission also now does not include any executive compensation in
20 rates.¹⁹

21 **Kansas** Plans based solely on financial goals are not allowed. For executive
22 incentive programs, the Commission also disallows 100% of plans based
23 on financial measures and 50% for plans using a balance of financial and
24 operational measures. The Commission has allowed in rates non-
25 executive annual incentive programs that have no focus on profitability or
26 earning.²⁰

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

¹⁸ 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.

¹⁹ The Commission's focus on customer benefit is reflected in the direct testimony of Staff witness Leckie, and in the final order for the recent IPC General Rate Case 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.

²⁰ In the litigated 2010 KCP&L rate case (10-KCPE-415-RTS) the Commission also stated that relying on peer group statistics "can result in a continuing upward spiral [instead] the Commission must examine the elements of incentive packages, and the behavior they incent." The Commission held that a focus on profitability or earning might incent employee behavior "detrimental to customers."

1 measures, the commission has excluded 50% of the annual plans. 100%
2 of the executive stock plans are excluded.²⁶

3 **Oregon** The commission's general policy is to evaluate plans based on whether
4 they benefit the customers or the company. Customer-based plans
5 involving reliability, response speed, etc. are called "merit" (operational)
6 plans. Company-based plans which track increases to the bottom line,
7 ROE, etc. are called "performance" (financial) plans. 50% of the cost of
8 merit plans is disallowed and 75% of the performance plans is disallowed.
9 100% of officer bonuses are disallowed.²⁷

10 **S. Dakota** The commission's general policy is to disallow the portion of incentive
11 plans that are based on the company's financial performance.²⁸ Current
12 treatment also includes disallowing both executive and non-executive
13 management incentive compensation. There are no incentive
14 compensation plans for union employees. Several utilities have whole
15 incentive programs that hinge on whether or not the company earns a
16 certain return. These financial prerequisites cause the whole plans to be
17 excluded from rates.

18 **Texas** The general rule is that incentive payments designed to improve the
19 financial performance of the utility are excluded. For example, in PUC
20 Docket No. 28840,²⁹ the commission disallowed sixty-six percent (66%)
21 of AEP-Texas Central's test year incentive payments in the amount of
22 \$4.2 million. This was the portion of the utility's incentive payments that
23 were based on financial performance measures.³⁰

24 **Utah** The commission's general policy is to allow in rates the parts of a plan
25 that are tied to ratepayer benefit and disallow the parts tied to financial
26 goals. Equity-based incentive compensation is excluded from rates.³¹

²⁶ See e.g., AEP-PSO Cause No. PUD 06-285; OG&E Cause No. PUD 05-151; and ONG Cause No. PUD 04-610.

²⁷ A recent order reflecting this policy can be found in Docket UE 197, Order No. 09-020.

²⁸ 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 of 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."

²⁹ *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840; SOAH Docket No. 473-04-1033, Final Order (August 15, 2005).

³⁰ See ALJ's Proposal for Decision at page 113 in PUC Docket No. 28840, SOAH Docket No. 473-04-1033, issued July 1, 2004. The PFD with respect to the treatment of incentive compensation was adopted by the Commission in its Final Order.

³¹ The recent 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 Comm. Rate Case Docket 95-049-05.

1 **Washington** Incentive plans are evaluated on a case by case basis. Incentives tied to
2 operational efficiency or other measures which benefit ratepayers are
3 allowed in rates and incentives based on return on earnings or other
4 measures that benefit the shareholders are disallowed.³²

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

States that use another approach

9 **Alaska** Incentive compensation is not an issue in rate cases in Alaska. Most of
10 utilities in Alaska are Cooperatives and Municipalities that do not provide
11 incentive pay. There is no relevant regulation or policy on the issue.

12 **Iowa** Incentive compensation is not typically an issue because few rate cases
13 are litigated in this jurisdiction. Both of the investor owned utilities in
14 Iowa are under rate freezes until 2013 and 2014. Mid-America has an
15 incentive compensation plan but has not filed a rate case in many years.
16 For the state's other utilities, it has been a long time since they have filed
17 a rate case or had a rate increase. The policy is to consider incentive
18 compensation plans on a case-by-case basis and to evaluate whether they
19 are reasonably and prudently incurred.
20

21 **Montana** Montana has no specific treatment directive and considers the issue on a
22 case by case basis. In a recent NorthWestern Energy rate case, as part of
23 a stipulation agreement, the company took a portion of its incentive
24 compensation out of rates, but reserved the right to propose that it be
25 included in a later filing.
26

27 **N. Dakota** Historically, North Dakota has followed the general policy that the
28 portion of incentive compensation that relates to shareholder earnings is
29 disallowed and the rest is included. Recently the commission chose to
30 consider overall compensation and determine whether it was reasonable
31 as compared to the market.³³ Executive incentive compensation is not
32 allowed in rates, and is typically not sought by the company.

³² See the Order in Pacific Power and Light Docket 061546.

³³ Other than Xcel, the utilities in North Dakota (Otter Tail and MDU) are highly diversified now (with mostly unregulated operations, e.g. MDU 90%). This allows utility executives to draw on the unregulated components for their compensation.

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

5 No. Even though regulators generally disallow incentive compensation tied to financial
6 performance for ratemaking purposes, utilities continue to include financial performance
7 as a key component of their plans. In my opinion, utilities continue to tie incentive
8 payments to financial performance because by doing so they achieve the primary
9 objective of the incentive plans: to increase corporate earnings and, thereby, earnings per
10 share (EPS). However, since the utility retains the increased earnings these plans help
11 achieve, payments for the plans should be made from a portion of these increased
12 earnings. Thus, properly designed incentive compensation plans need not be subsidized
13 by ratepayers.

14
15 **Q: UNDER THE COMPANY'S 2012 INCENTIVE PLAN, IS ANNUAL PAYMENT**
16 **UNCERTAIN AND DEPENDENT UPON FINANCIAL PERFORMANCE OF**
17 **THE COMPANY?**

18 **A:** The EPS Modifier allows AEP to significantly reduce incentive payments, or make no
19 incentive payments at all, if the threshold EPS goals are not met. In these situations,
20 amounts collected through rates for incentive programs would be retained by the
21 shareholders.

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

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

8
9 **Q: ARE THE AEPSC INCENTIVE PLANS ALSO BASED ON FINANCIAL**
10 **PERFORMANCE MEASURES?**

A: Yes. The AEPSC plans are all weighted heavily toward company goals and financial
performance measures in particular, much like the plan at the operating company level
discussed above. Although some of the AEPSC plans show some weighting toward
customer satisfaction, the "customers" AEPSC serves are generally the AEP affiliated
companies and the employees of these companies, not actual utility customers. Further,
all of the AEP plans are limited by the *EPS Modifier* which operates to ensure that
incentive payments are not made at the expense of reaching AEP's EPS objectives.

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

13 A: For ratemaking purposes, *all* of the cost of the AEP/PSO incentive plans could be
14 excluded, based on the fact that these plans are overwhelmingly weighted toward

1 company rather than customer objectives, and in particular, because the EPS Modifier
2 effectively retains the incentive money for shareholders to the extent shareholder value
3 objectives were not met each year. However, if from a policy perspective the
4 Commission wants to encourage a focus on customer concerns, the Commission could
5 include that portion of the plan costs that purports to be representative of customer
6 service and reliability goals. Overall, I believe no more than 50% inclusion in rates for
7 these plans would be appropriate.

8
9 **Q: IS YOUR RECOMMENDED TREATMENT CONSISTENT WITH OTHER**
10 **COMMISSIONS' TREATMENT OF AEP'S INCENTIVE PLANS?**

11 A: Yes. In PUC Docket No. 28840,³⁴ the Texas Public Utility Commission disallowed
12 sixty-six percent (66%) of AEP-Texas Central's test year annual incentive payments of
13 \$4.2 million. This was the portion of the utility's incentive payments that the Texas
14 Commission believed was based on financial performance measures at that time.³⁵ The
15 AEP/Texas Central incentive plans are the same company-wide plans used at AEP/PSO.
16 Also, in AEP SWEPCO's 2012 rate case, Docket No. 40443, the Texas commission
17 again disallowed the portion of SWEPCO's annual incentive plan related to financial
18 performance measures.

³⁴ *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840; SOAH Docket No. 4 73-04-1033, Final Order (August 15, 2005)

³⁵ See ALJ's Proposal for Decision at page 113 in PUC Docket No. 28840, SOAH Docket No. 473-04-1033, issued July 1, 2004. The PFD with respect to the treatment of incentive compensation was adopted by the Commission in its Final Order.

1

2 **Q: WILL AEP BE FINANCIALLY HARMED FROM YOUR RECOMMENDATION**
3 **TO EXCLUDE INCENTIVE COMPENSATION PAYMENTS?**

4 A: No. AEP/PSO's incentive compensation payments are discretionary payments limited
5 by the Company's *EPS Modifier*. The *EPS Modifier* ensures that the incentive payments
6 are not made at the expense of reaching the Company's EPS goals. In those years when
7 the EPS targets are achieved, the additional funds needed to make the incentive
8 payments to employees will have been made available through the increased earnings
9 that resulted from reaching these EPS goals.

10

11 **Q: WHAT RATIONALE DOES THE COMPANY PROVIDED FOR INCLUDING**
12 **ITS ANNUAL INCENTIVE PLAN IN RATES?**

13 A: The Company argues that incentives are part of an overall compensation package that is
14 designed to attract and retain qualified personnel. Since other utilities offer incentive
15 plans to their employees, the company would run the risk of not being able to compete
16 for key personnel if it did not offer a comparable plan.³⁶

17

18 **Q: IS THIS ARGUMENT PLAUSIBLE?**

19 A: No. The problem with the Company's argument is that when utilities such as PSO
20 compete with other utilities for qualified personnel, and the incentive compensation
21 plans of these other utilities are being reduced, for ratemaking purposes, for the portion

³⁶ See for example, the direct testimony of Andrew Carlin at page 16, lines 9-12.

1 of the plans tied to financial performance, PSO is not put at a competitive disadvantage
2 when its incentive compensation costs are similarly reduced.

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

8
9 **Q: DO YOU TAKE INTO ACCOUNT PSO'S ADJUSTMENT TO REDUCE TEST**
10 **YEAR INCENTIVE PLAN EXPENSE TO TARGETED LEVELS?**

11 A: Yes. I accepted the Company's *targeted* levels for incentive payments and made my
12 adjustments for financial-performance measures to the lower targeted levels rather than
13 to the higher actual test year levels.

14
15 **Q: WHAT IS THE LEVEL OF INCENTIVE PAYMENTS INCLUDED IN PSO'S**
16 **PRO FORMA EXPENSE IN THIS APPLICATION?**

17 A: According to PSO's responses to AG Data Requests 3-9 Att.1 and 3-11, Att. 2, PSO
18 included \$8,236,889 in pro forma operating expense for its annual incentive plans for all
19 employees.

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

2 A: OIEC's adjustment to operating expense for regular incentives is set forth below and can
3 be seen at *Exhibit MG-2.5*.

4 Annual Incentive Plan Payments in Pro Forma Expense	\$8,239,889
5 Percentage Associated with Company Financial Goals	<u>50 %</u>
6 OIEC's Adjustment to Annual Incentive Plans	<u>\$ 4,118,445</u>

7
8 **Q: ARE YOU AWARE OF OTHER STATES THAT USE A 50/50 SHARING**
9 **APPROACH FOR ANNUAL INCENTIVE PLANS?**

10 A: Yes. Several states recognize the difficulty of allocating the benefits derived from incentives
11 plans between shareholders and ratepayers, when these plans contain both financial and
12 operational measures.

13 **Arizona:** The commission follows the general rule that costs associated with
14 financial performance are excluded. In practice, this means that the costs of long-term plans
15 are excluded altogether and the costs of the short term annual cash plans are shared 50/50
16 between shareholders and ratepayers.³⁷

17 **Arkansas:** In the recent Entergy Arkansas rate case the Arkansas commission
18 disallowed 50% of the Company's annual incentive plan because the plan had a funding
19 mechanism similar to the funding mechanism used by AEP, where the amount paid for
20 incentives each year depends on how much money the utility makes that year.³⁸

21 **Oregon:** Customer-based plans involving reliability, response speed, *etc.* are called
22 "merit" (operational) plans. Company-based plans which track increases to the bottom line,

³⁷ See for example, APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.

³⁸ Docket No. 13-028-U.

1 ROE, etc. are called “performance” (financial) plans. 50% of the cost of merit plans is
2 disallowed and 75% of the performance plans is disallowed.

3 **Kansas:** Plans based solely on financial goals are not allowed. For executive
4 incentive programs, the Commission also disallows 100% of plans based on financial
5 measures and 50% for plans using a balance of financial and operational measures.

6
7 **Q: HAVE YOU PROPOSED ANY OTHER ADJUSTMENTS WITH RESPECT TO THE**
8 **COMPANY’S ANNUAL INCENTIVE COSTS?**

9 A: Yes. I made an adjustment to remove from pro forma expense the Company’s labor
10 attendant costs associated with the 50% disallowance of short term incentives. This
11 adjustment is set forth below and can be seen at *Exhibit MG-2.5*.

12
13 **OIEC Adjustment to Remove Labor Attendant Costs** **\$ 227,156**

14
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 \$3,554,117 for its long-term incentive plan, which
19 is the amount in pro forma operating expense after PSO’s adjustment to increase test
20 year expense to *targeted* levels for long-term incentives.

21
22 **Q: WHAT TYPES OF INCENTIVES ARE PROVIDED TO SENIOR**
23 **MANAGEMENT AT AEP AND PSO?**

1 A: Along with the company-wide incentive plans discussed above, senior managers of the
2 Company are provided additional incentive compensation through AEP's Long-Term
3 Incentive Plan.³⁹ This plan provides grants and awards in the form of *performance units*
4 and *restricted stock units* (RSUs) both of which are generally similar in value to shares
5 of AEP common stock.⁴⁰ The performance units are granted based on two equally
6 weighted performance measures which are equally weighted between three-year total
7 shareholder returns and three-year cumulative EPS relative to a Board-approved target.
8 As such, the Long-Term Incentive Plan is designed to align the interest of AEP's
9 management with the interest of shareholders and to promote the financial success and
10 growth of AEP.

11
12 **Q: DO YOU RECOMMEND THE INCLUSION OF THE LONG-TERM**
13 **INCENTIVE EXPENSE IN RATES?**

14 A: No. Incentive compensation payments to officers, executives and key employees of a
15 utility are generally excluded for ratemaking purposes, and I agree with this treatment.
16 Since officers of any corporation have a duty of loyalty to the corporation itself and not
17 to the customers of the company, these individuals typically put the interests of the
18 company first. Undoubtedly, the interests of the company and the interests of the
19 customer are not always the same, and at times, can be quite divergent. This natural
20 divergence of interests creates a situation where not every cost associated with executive
21 compensation is presumed to be a necessary cost of providing utility service. Many

³⁹ See Carlin Direct Testimony, pages 26-27.

⁴⁰ Carlin Direct Testimony at page 27.

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

15
16 **Q: HOW IS LONG-TERM INCENTIVE COMPENSATION TREATED IN OTHER**
17 **STATES?**

18 A: The results of the Garrett Group Incentive Survey, discussed in the previous section of
19 this testimony, show that most states follow the general rule that incentive pay associated
20 with financial performance is not allowed in rates. This means that long-term, stock-
21 based incentives are not allowed in most states. In the synopsis of the incentive survey
22 results from each state that was included in the prior section of this testimony, the

1 treatment of executive incentives in each state was underlined. According to the survey,
2 the following western states exclude all or virtually all executive incentive pay: Oregon,
3 California, Nevada, Idaho, Utah, South Dakota, Oklahoma, Wyoming, North Dakota,
4 Missouri, Arkansas, Louisiana and Minnesota. Other states, like Washington, Missouri
5 and Texas, apply the *financial performance* rule, which has the affect of excluding
6 executive incentives, especially stock-based awards.

7
8 **Q: IS YOUR RECOMMENDED TREATMENT TO EXCLUDE LONG-TERM**
9 **INCENTIVE COMPENSATION TO SENIOR MANAGEMENT CONSISTENT**
10 **WITH THE TREATMENT GENERALLY PRESCRIBED IN OTHER STATES?**

11 A: Yes. In our survey of incentive treatment in other states, we found that most
12 commissions exclude executive stock-based compensation, such as AEP's Long-Term
13 Incentive Plan.

14
15 **Q: IS YOUR RECOMMENDED TREATMENT TO EXCLUDE LONG-TERM**
16 **INCENTIVE COMPENSATION CONSISTENT WITH THE TREATMENT OF**
17 **LONG-TERM INCENTIVES IN OKLAHOMA?**

18 A: Yes. In Oklahoma, long-term incentives tied to corporate earnings are excluded. In
19 PSO's last two litigated rate cases, 100% of the costs of the long-term incentive plans
20 were excluded.⁴¹

21

⁴¹ Cause Nos. PUD 200600285 and PUD 200800144.

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

3 A: Generally, utilities argue that executive incentives are part of an overall compensation
4 package that is designed to attract and retain qualified personnel. Since other utilities
5 offer incentive plans to their executives, a company would run the risk of not being able
6 to compete for key personnel if it did not offer a comparable plan.⁴²

7

8 **Q: IS THIS ARGUMENT PLAUSIBLE?**

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

17 Further, when utilities, such as AEP/PSO, compete with other utilities for
18 qualified executives, and the executive incentive compensation plans of the other utilities
19 are not being recovered through rates, AEP/PSO is not put at a disadvantage when its
20 executive incentive compensation is excluded as well. Since most states exclude
21 executive incentive pay as a matter of course and most other states exclude executive
22 incentives as a practical matter, AEP/PSO would actually be given an unfair advantage if

1 its executive plans were included in rates. The fact that other utilities offer executive
2 incentive plans is not relevant; what is relevant is the fact that other utilities are not
3 recovering the costs of these plans in rates. In an order disallowing Nevada Power's
4 long-term incentive plan, the Nevada Commission articulated this important ratemaking
5 concept as follows:

6 Therefore the Commission accepts BCP's and SNHG's
7 recommendations to disallow recovery of expenses associated with
8 LTIP. Both parties provide a valid argument that this type of
9 incentive plan is mainly for the benefit of shareholders. Further,
10 both BCP and SNHG provide examples of numerous other
11 jurisdictions that do not allow the recovery of these costs and,
12 therefore, disallowance in this instance would not place NPC in a
13 competitive disadvantage.⁴³ (Emphasis added).

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

16 A: I recommend that all of the cost of AEP's Long-Term Incentive Plan be excluded from
17 rates. OIEC's adjustment removes 100% of the cost of the plan included in pro forma
18 operating expense in the amount of \$3,554,117. The calculations supporting this
19 adjustment are set forth at *Exhibit MG-2.5*.

20 **OIEC Adjustment to Exclude 100% of the Long-Term Incentives \$ 3,554,117.**

III. C. SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP")

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

⁴² See for example, the direct testimony of Andrew Carlin at page 32.

⁴³ See Final Order in Docket 08-12002 at paragraph 549.

1 A: The Company provides supplemental retirement benefits to officers, and division presidents
2 of the Company. Supplemental retirement plans for highly compensated individuals are
3 provided because benefits under the general pension plans are subject to certain limitations
4 under the Internal Revenue Code. Benefits payable under these supplemental plans are
5 typically equivalent to the amounts that would have been paid but for the limitations
6 imposed by the Code. In general, the limitations imposed by the Code allow for the
7 computation of benefits on annual compensation levels of up to \$255,000 for 2013.
8 Retirement benefits on compensation levels in excess of the \$255,000 limitation are paid
9 through supplemental plans. Supplemental retirement plans for highly compensated
10 employees are designed to provide benefits in addition to the benefits provided under the
11 general pension plans of the company.

12
13 **Q: WHAT AMOUNTS WERE INCLUDED IN PRO FORMA OPERATING EXPENSE**
14 **FOR THE SUPPLEMENTAL EXECUTIVE PENSION PLAN?**

15 A: The amount of SERP costs included in PSO's filed cost-of-service was \$359,450.⁴⁴

16
17 **Q: WHAT DO YOU RECOMMEND WITH RESPECT TO SUPPLEMENTAL**
18 **EXECUTIVE RETIREMENT COSTS?**

19 A: Yes. I recommend a sharing of the total executive benefits costs as follows: I
20 recommend that ratepayers pay for all of the executive benefits included in the
21 Company's regular pension plans, and that shareholders pay for the additional executive
22 benefits included in the supplemental plan. For ratemaking purposes, shareholders

1 should bear the additional costs associated with supplemental benefits to highly
2 compensated executives, since these costs are not necessary for the provision of utility
3 service, but are instead discretionary costs of the shareholders designed to attract, retain
4 and reward highly compensated employees. Further, because officers of any corporation
5 have a duty of loyalty to the corporation, these individuals are required to put the interest
6 of the company first. This creates a situation where not every cost associated with
7 executive compensation is presumed to be a cost appropriately passed on to ratepayers.
8 Many regulators are inclined to exclude executive bonuses, incentive compensation and
9 supplemental benefits from utility rates, understanding that these costs would be better
10 borne by the utility shareholders.⁴⁵

11
12 **Q: HAS THIS COMMISSION ORDERED A DISALLOWANCE OF SERP**
13 **EXPENSE IN PRIOR CASES?**

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

16 q. **Employee Benefits-Supplemental Executive Retirement**
17 **Plan ("SERP").**

18
19 PSO included \$596,081 as Supplemental Executive Retirement
20 Plan ("SERP") in its cost-of-service. The Commission adopts
21 OIEC's proposal to remove the SERP Expense from the revenue
22 requirement in this proceeding. The Commission adopts OIEC's
23 recommendation that ratepayers pay for all of the executive
24 benefits included in PSO's regular pension plans and that
25 shareholders pay for the additional executive benefits included in
26 the supplemental plan.

⁴⁴ See Response to OIEC Data Request 4.1.

⁴⁵ For example, this Commission excluded SERP costs in PSO's last two litigated rate case, PUD 06-285 and PUD 08-144.

1 Again, in PSO's 2008 rate case, Cause No. PUD 200800144, the Commission disallowed
2 100% of the Company's SERP expense.

3 **11. Supplemental Executive Retirement Plan ("SERP").**
4

5 The AG and OIEC recommend reductions to reflect the
6 elimination of SERP expense from PSO's cost of service. Staff
7 proposed no adjustment to PSO's recommendation. SERP is
8 AEP's non-qualified defined benefit retirement plan that PSO
9 argued allows AEP the flexibility to attract and retain key
10 employees and provides benefits that cannot be provided under
11 AEP's qualified defined benefit plans. PSO stated that the
12 combined plans, of which SERP is a part, allow employees to
13 accumulate an appropriate level of replacement income upon
14 retirement. According to PSO, SERP plans and other benefits are
15 part of a market competitive benefits program for the utility
16 industry and large employers in general. The Commission finds
17 that the SERP expenses do not provide a benefit to the ratepayers
18 of PSO and therefore adopts the recommendation of the AG and
19 OIEC to deny recovery of these costs from PSO's ratepayers.

20
21 **Q: HOW IS SERP EXPENSE TREATED IN OTHER STATES WHERE YOU HAVE
22 PROVIDED TESTIMONY ON THIS ISSUE?**

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

1 this Docket, the Arkansas Commission determined that SERP expenses are not necessary
2 to provide utility service, but rather are discretionary costs implemented by Entergy
3 Arkansas and therefore should be disallowed. In Texas, in Entergy's last rate case,
4 Docket No. 39896, the Texas PUC disallowed all of the Company's SERP costs.

5 140. ETI provides non-qualified supplemental executive
6 retirement plans for highly compensated individuals such as key
7 managerial employees and executives that, because of limitations
8 imposed under the Internal Revenue Code, would otherwise not
9 receive retirement benefits on their annual compensation over
10 \$245,000 per year.

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

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

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

3 A: I have not conducted a comprehensive study of SERP treatment in other states, but I do
4 know that SERP is disallowed in the states of Oregon,⁴⁶ Idaho,⁴⁷ and Arizona as well.

5
6 **Q: WHAT ADJUSTMENT ARE YOU RECOMMENDING?**

7 A: This adjustment is set forth below and the calculations supporting the adjustment can be
8 seen at *Exhibit MG2.6*.

9 **OIEC Adjustment to Remove SERP Expense** **\$359,450**

III. D. PSO LABOR COST ANNUALIZATION AT 6-MONTH CUT OFF

10 **Q: HAVE YOU REVIEWED PSO'S PROPOSED PAYROLL ADJUSTMENT?**

11 A: Yes. PSO's proposed adjustment contains two major components: (1) an annualization
12 of payroll levels at test year end, July 31, 2013, and (2) an increase for post-test year pay
13 raises, calculated by multiplying payroll costs times the nominal rate of the pay raise.
14 PSO's adjustment included raises awarded shortly after test year end and much larger

⁴⁶ 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."

⁴⁷ 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.

1 projected raises that might be implemented by April 2014, a full eight months after the
2 test year end.⁴⁸ PSO's adjustment results in a net requested increase to payroll of
3 \$2,447,734 on a total company basis.⁴⁹
4

5 **Q: DO YOU AGREE WITH PSO'S PROPOSED ADJUSTMENT?**

6 A: No. In Oklahoma, the Commission is required by law (Title 17 § 284) to give effect to
7 known and measurable changes that occur within six months of test year end. In this
8 application, the six month cut-off period for post-test year adjustments is January 31,
9 2014. A payroll annualization at, or near, January 31, 2014 would include all changes to
10 payroll that have occurred by that time.

11 By contrast, the Company's proposed adjustment, which annualizes payroll at
12 test year end, and then proposes *to increase* payroll expense based on the nominal
13 amount of pay raises that might be awarded well after test year end, is not an accurate
14 approach. The Company's method assumes that post test year pay raises increase
15 payroll expense by the same percentage amount as the pay raise. This is not a valid
16 assumption. The Company's approach fails to consider that other events occurring
17 during the same time period may decrease payroll levels by as much or even greater
18 amounts.
19

20 **Q: DID THE COMPANY PROVIDE AN ANNUALIZATION OF PAYROLL COSTS**
21 **AT JANUARY 31, 2014 IN RESPONSE TO DISCOVERY?**

48 See PSO response to AG 4.11.

1 A: Yes. The Company provided annualized labor at January 31, 2014 in response to AG
2 2.13, but included in that response additional pay raises projected to occur beyond the
3 January 31 cut-off. When the additional pay raises beyond the 6-month cut-off are
4 removed, the actual annualized payroll at January 31, 2014 is \$74,949,635. When that
5 amount is multiplied by the payroll expense factor of 70.98% a total Company payroll
6 expense of \$53,199,251 is produced, which is \$725,117 lower than the pro forma payroll
7 level requested by the Company.

8

9 **Q: WHAT IS YOUR ADJUSTMENT TO PAYROLL EXPENSE?**

10 A: I recommend that PSO's requested payroll cost be reduced by \$725,117 to reflect the
11 annualized cost at January 31, 2014. I also recommend that payroll tax expense be
12 reduced by \$52,703. The calculations for these adjustments can be *Exhibit MG2.7*.

49 See W/P H.04.4.

III. E. AEPSC LABOR COST ANNUALIZATION AT 6-MONTH CUT OFF

1 **Q: HAVE YOU REVIEWED THE COMPANY'S REQUESTED INCREASE FOR**
2 **AEPSC LABOR COST?**

3 A: Yes. The Company has requested an increase of \$798,429 for AEPSC Regular Payroll
4 charges to PSO. In reviewing this request, I reviewed the AEPSC Payroll charged by
5 pay period from August 2013 through January 2014.

6
7 **Q: DO YOU AGREE WITH THE COMPANY'S PROPOSED INCREASE?**

8 A: No. Based on my review of the AEPSC Payroll data, the regular payroll charges trended
9 significantly lower over this time period. Rather than justifying an increase for
10 ratemaking purposes as the Company proposes, it appears the payroll levels at the six
11 month cut-off should be annualized, and an adjustment should be made to decrease the
12 AEPSC payroll charged to PSO for ratemaking purposes. I performed three alternative
13 methods to annualize the AEPSC payroll data, which are set forth on Table 6 below.
14 First, I annualized the one month payroll data for the month of January 2014. Based on
15 this calculation the net decrease to AEPSC payroll would be \$9,323,777. Next, I
16 annualized the two-month period of December 2013-January 2014, which yielded a net
17 decrease of \$7,321,001. Finally, I annualized the three-month period from November
18 2013-January 2014, which yielded a net decrease of \$3,110,579. Each of the
19 annualization scenarios demonstrated a significant drop in AEPSC payroll charges and
20 any of the three methods could be used to establish the ongoing AEPSC charges allowed
21 for ratemaking purposes. However to be conservative, I recommend the method

1 resulting in the lowest decrease, which is the third scenario, the annualization of the
 2 quarter ended January 31, 2014. After reversing PSO's requested increase, the resulting
 3 net decrease in AEPSC payroll charges is \$3,110,579. Based upon this decrease in
 4 AEPSC payroll charges, a corresponding payroll tax adjustment is needed at the tax rate
 5 of 7.27%. This associated adjustment to reduce payroll taxes by \$226,139 is also shown
 6 in the table below and set forth at *Exhibit MG2.8* attached to this testimony.

TABLE 6: OIEC Annualized AEPSC Regular Payroll At 6-Month Cut-Off

Ln	Description	Scenario 1 January 2014	Scenario 2 Dec 2013 – Jan 2014	Scenario 3 Nov 2013 – Jan 2014
1	Annualized Payroll at January 31, 2014	\$56,585,440	\$59,407,046	\$65,338,889
2	Test Year Payroll Costs	68,596,356	68,596,356	68,596,356
3	Base Adjustment to 6-Month Level	(12,010,916)	(9,189,310)	(3,257,467)
4	Expense Percentage (70.98%)	(8,525,348)	(6,522,572)	(2,312,150)
5	Adjust to Reverse PSO's Requested Increase	(798,429)	(798,429)	(798,429)
6	Adjust to Annualize Payroll at 6-Month Level	(9,323,777)	(7,321,001)	(3,110,579)
7	OIEC Payroll Annualization Adjustment			<u>\$ (3,110,579)</u>
8	OIEC Payroll Annualization Adjustment - Payroll Tax - 7.27%			<u>\$ (226,139)</u>

III. F. RATE CASE EXPENSE

1 **Q: WHAT IS THE ISSUE REGARDING RATE CASE EXPENSE?**

2 A: The Company seeks to recover estimated rate case costs in this case of \$750,000. To
3 calculate its pro forma adjustment in this case, the Company reduces the total estimated
4 rate case costs of \$750,000 by \$248,367 of over-recovered rate case costs from the last
5 rate case (PUD 201000050), and then amortizes the remaining balance of \$491,633 over
6 an 18-month amortization period to arrive at its recommended adjustment of \$327,755.
7 The problem with the Company’s adjustment is that, by the time new rates go into effect
8 in this case the over-recoveries from the last case will have grown by another year which
9 is not reflected in the Company’s calculation.

10 The amount the Company will recover from August 2013 through July 2014 is an
11 additional \$428,435, which will be sufficient to recover most of the Company’s
12 estimated costs in this case. In other words, the amount embedded in rates in the
13 Company’s last rate case will recover all of the costs from the prior case and most of the
14 costs from this case by the time new rates go into effect. In fact, all but \$63,198 of the
15 Company’s original *estimated* total rate case costs will be recovered before the new rate
16 period begins.

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

19 No. In my view, the Company’s estimated rate case costs are overstated. First, the
20 Company’s original estimate includes \$200,000 for a Return on Equity (“ROE”) witness.
21 The market price for an ROE witness is between \$25,000 and \$50,000. Even if you

1 escalate the high end of that range by 50% you only get to \$75,000. Based on this
2 inflated line item alone, it appears the Company's original estimated rate case costs are
3 overstated by at least \$125,000. Ratepayers should not be burdened with unreasonably
4 overstated fees for the Company's ROE witness. Second, as of February 2014, the
5 Company had only spent \$281,000 of its original \$750,000 estimate. It does not appear
6 the Company could, or should, spend the full amount of original estimate by the end of
7 this case. Because the Company's original number should be lower by *at least*
8 \$125,000, the over-recoveries from the prior case will completely cover the costs from
9 this case by the time new rates go into effect.

10
11 **Q: WHAT ADJUSTMENT ARE YOU RECOMMENDING?**

12 A: I recommend that the Company's pro forma adjustment of \$327,755 be reversed. There
13 is no need to include any amount for rate case costs because the Company will have fully
14 recovered its costs for this case by the time new rates go into effect. The calculations
15 supporting this recommendation can be seen at *Exhibit MG2.9*.

16
17 **OIEC adjustment to reverse the Company's pro forma adjustment (\$327,755)**

IV. DEPRECIATION EXPENSE

1 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY WITH RESPECT TO THE**
2 **COMPANY’S PROPOSED DEPRECIATION RATES?**

3 A: In this application, PSO proposes to increase its revenue requirement by \$30,505,024.00
4 to reflect the Company’s higher plant balances and new proposed higher depreciation
5 rates. OIEC’s recommendations regarding depreciation rates are set forth in the
6 responsive testimony of Mr. Jacob Pous. Mr. Pous recommends that the Commission
7 order PSO to continue to use the depreciation rates established by this Commission in
8 the Company’s last general rate case, Cause No. PUD 201000050. The Company has
9 provided no credible depreciation study or testimony in this docket that would support a
10 change at this time from the previous order. My testimony supports OIEC’s
11 recommendation to retain the Commission-ordered depreciation rates from the prior
12 cause by reversing the Company’s proposed increase for the new higher rates. OIEC’s
13 depreciation adjustment (1) decreases pro forma depreciation expense to reverse the
14 Company’s proposed increase of \$30,505,024 and (2) increases depreciation expense by
15 \$3,879,710 to reflect the application of existing depreciation rates to plant balances at
16 January 31, 2014, the 6-month post test year cutoff. OIEC’s net adjustment to
17 depreciation expense is \$26,625,314 and is set forth below and can be seen at *Exhibit*
18 *MG-2.10*.

19	OIEC’s Adjustment to Reverse PSO’s Proposed Increase	(\$30,505,024)
20	OIEC’s Adjustment to Reflect Annualized Depreciation at 1/31/14	<u>\$3,879,710</u>
21	OIEC Net Adjustment to Pro Forma Depreciation Expense	<u>(\$26,625,314)</u>

V. ADJUSTMENTS PROPOSED BY OTHER OIEC WITNESSES

1 Q: WHAT IS THE IMPACT OF THE ADJUSTMENTS PROPOSED BY OTHER
2 OIEC WITNESSES?

3 A: The impact of the recommendations of the other OIEC witnesses is set forth in the table
4 below:

TABLE 7: OTHER OIEC WITNESS RECOMMENDATION IMPACTS		
1	Dave Parcell – Cost of Capital Impact	<u>\$ (18,072,975)</u>
2	Jack Pous – Depreciation Expense Impact	<u>\$ (26,625,314)</u>

5 VI. CONCLUSION

6 Q: WHAT IS THE OVERALL IMPACT OF OIEC RECOMMENDATIONS ON THE
7 COMPANY’S REVENUE REQUIREMENTS?

8 A: The overall impact of the OIEC adjustments on PSO’s requested revenue requirement on
9 a total company basis is set forth below. OIEC’s recommendations result in an overall
10 \$22,196,431 rate decrease.

11	Rate Increase Proposed by PSO	\$37,305,012
12	OIEC Adjustments	<u>(\$59,501,443)</u>
13	Rate Decrease Proposed by OIEC	<u>(\$22,196,431)</u>

14 Q: DO YOU HAVE ANY FURTHER OTHER COMMENTS?

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

1 interpreted as agreement with the Company's position on my part.

2

3 **Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?**

4 A: Yes, it does. However, I reserve the right to update and amend my revenue requirement
5 recommendations based on the responsive testimony filed by other parties and the
6 rebuttal testimony filed by PSO. My recommendations in the rate design phase may also
7 affect my overall revenue requirement recommendations. I will file final OIEC revenue
8 requirement exhibits with my surrebuttal issues filing.

9 1985196.1:620435:01675

MARK E. GARRETT

CONTACT INFORMATION:

11713 N.W. 120th Street
Yukon, OK 73099
(405) 239-2226

EDUCATION:

Juris Doctor Degree, Cum Laude, 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:

CONSULTING PRACTICE (1995 - Present) Participate 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. Review management decisions of regulated utility companies for reasonableness from a ratemaking perspective, especially in proceedings to review the reasonableness of prices paid for natural gas supplies, natural gas transportation, coal supplies, coal transportation and purchased power. Participate 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. Participate in regulatory proceedings to restructure the electric and natural gas utility industries.

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1995) 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 for Real Estate Development Company with \$300 million in assets (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, CPA's - Auditor (1985 - 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. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participating 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.
2. **Nevada Power Company, 2011, (Docket No. 11-04010)** - Participating as an expert witness on behalf of the Southern Nevada Hotel Group¹ before the Nevada PUC to sponsored written and oral testimony to address proposed changes to the Company’s customer deposit rules.
3. **Nevada Power Company, 2011, (Docket No. 11-06006)** - Participating as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to 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.
4. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participating 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.
5. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087)** – Participating 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.
6. **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.
7. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the Oklahoma Industrial Energy Consumers (“OIEC”) before the OCC in OG&E’s application seeking to include retire medical expense in the Company’s pension tracker mechanism.
8. **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.
9. **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 to address PSCo’s proposed Environmental Tariff.
10. **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”) before the Arkansas Public Service Commission in OG&E’s general rate case application to provide testimony

¹ The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas

on various revenue requirement, cost of service and rate design issues.

11. **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.
12. **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
13. **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.
14. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participating 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.
15. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147)** – Participating 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.
16. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participating 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.
17. **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.
18. **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.
19. **Nevada Power Company, 2010 (Docket No. 10-02009)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”)² 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.
20. **Entergy Texas Inc., 2010 (PUC Docket No. 37744)** – Participating as an expert witness on behalf of

² The Southern Nevada Hotel Group consists of the Boyd, MGM Mirage, Stations and Wynn properties in Las Vegas.

the Cities³ in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

21. **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.
22. **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.
23. **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.
24. **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.
25. **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.
26. **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.
27. **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.
28. **Rocky Mountain Power, 2009 (Docket No. 08-035-38)** – Participated as an expert witness on behalf of the Division of Public Utilities in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.
29. **Texas-New Mexico Power Co., 2008 (Docket 36025)** – Participating 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.
30. **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

3 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

revenue requirement and rate design issues to establish prospective cost-of-service based rates.

31. **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.
32. **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.
33. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334)** – Participated as an expert witness on behalf of the Cities⁴ in EGSI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
34. **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.
35. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447)** – Participating 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 SO₂ allowances.
36. **Rocky Mountain Power, 2008 (Docket No. 07-035-93)** – Participating as an expert witness on behalf of Staff in PacifiCorp’s general rate case to provide testimony on various revenue requirement issues.
37. **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.
38. **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 SO₂ allowances.
39. **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.
40. **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.
41. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030)** – Participated as an expert

⁴ 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

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.

42. **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.
43. **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.
44. **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.
45. **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.
46. **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.
47. **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.
48. **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.
49. **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 SO₂ allowance proceeds.
50. **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.
51. **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.

52. **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.
53. **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.
54. **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.
55. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participating 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.
56. **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.
57. **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:
58. **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.
59. **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.
60. **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.
61. **Oklahoma Gas & Electric Co., 2003** – Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application before the OCC to address numerous rate base, operating expense and rate design issues for the purpose of setting prospective cost-of-service based rates.

62. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076)** – Participating 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.
63. **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.
64. **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.
65. **McCarthy Family Farms, 2003** – Participated as a consultant to assist in converting a biomass and biosolids composting process into a renewable energy power producing business in California.
66. **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.
67. **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.
68. **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.
69. **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.
70. **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.
71. **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.
72. **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.

73. **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.
74. **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.
75. **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.
76. **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.
77. **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.
78. **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.
79. **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.
80. **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.
81. **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.
82. **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.
 83. **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.
 84. **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.
 85. **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.
 86. **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.
 87. **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.
 88. **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.
 89. **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.
 90. **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.
 91. **Enogex, Inc., 1995 (FERC 95-10-000)** - Analyzed Enogex's application before the FERC to increase

gas transportation rates for third party shippers and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.

92. **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.
93. **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.
94. **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.
95. **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.
96. **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 201300217
Test Year Ended July 31, 2013

Ln.	Descriptions	Witness	Ref.	Rate Base Items	ROR W/Tax	Total Company Impact
1	PSO Requested Rate Increase		Sch B-01			\$ 37,305,012
2						
3	Rate Base		Sch B-01	\$ 1,865,522,788		
4						
5	Adjust Plant Investment to 6-Month Level	Garrett	MG2.1	86,428,109	11.206%	9,685,134
6	Adjust Accumulated Depreciation to 6-Month Level	Garrett	MG2.1	(16,117,103)	11.206%	(1,806,083)
7	Adjust ADFIT to 6-Month Level	Garrett	MG2.2	(20,309,287)	11.206%	(2,275,859)
8	Adjust Fuel Inventory to 6-Month Level	Garrett	MG2.3	(2,359,001)	11.206%	(264,350)
9	Adjust Prepayments to 6-Month Level	Garrett	MG2.3	(5,631,770)	11.206%	(631,096)
10	Remove New Regulatory Asset for July 2013 Storm	Garrett	MG2.3	(10,000,000)	11.206%	(1,120,600)
11	Remove Prepaid Pensions from Rate Base	Garrett	MG2.4	(67,747,716)	11.206%	(7,591,809)
12	Remove Capitalized Incentives	Garrett	MG2.5	<u>(22,307,762)</u>	11.206%	<u>(2,499,808)</u>
13	Total Rate Base Adjustments			\$ (58,044,530)		\$ (6,504,471)
14						
15	Cost of Capital					
16						
17	PSO Requested Pre-Tax Rate of Return		MG2.11		11.206%	
18	OIEC Reduction to Pre-Tax Rate of Return	Parcell	9.25%	\$ 1,807,478,258	<u>-1.000%</u>	\$ (18,072,975)
19	OIEC Recommended Pre-Tax Rate of Return				<u>10.206%</u>	
20						
21	Revenue and Expense Adjustments					
22						
23	Revenue Adjustments (Growth and Weather)	Garrett	TBA			-
23	Increase for Pension Fund Return on Prepaid Pensions	Garrett	MG2.4			4,403,602
24	Remove 50% of Annual Incentive Plan	Garrett	MG2.5			(4,118,445)
25	Remove 100% of Executive Incentive Plan	Garrett	MG2.5			(3,554,117)
26	Remove Incentive Labor Attendant Costs	Garrett	MG2.5			(227,156)
27	Remove Supplemental Executive Retirement Costs	Garrett	MG2.6			(359,450)
28	Adjust PSO Payroll to 6-Month Levels	Garrett	MG2.7			(778,644)
29	Adjust AEPSC Payroll to 6-Month Levels	Garrett	MG2.8			(3,336,718)
30	Adjust Rate Case Expenses	Garrett	MG2.9			(327,755)
31	Adjust Proposed Depreciation Rates to Existing Rates	Pous	MG2.10			<u>(26,625,314)</u>
32	Total Operating Revenue & Expense Adjustments					\$ (34,923,997)
33						
34	Total Impact of OIEC Adjustments					<u>\$ (59,501,443)</u>
35						
36	OIEC Proposed Rate Decrease					<u>\$ (22,196,431)</u>

PUBLIC SERVICE COMPANY OF OKLAHOMA
 OIEC WORKPAPERS - ADJUSTMENT TO PLANT IN SERVICE
 Test Year Ended 07-31-13
 Cause NO. PUD 201300217

Line No.	Description	Plant Balances 1/31/2014	Reference	PSO Pro Forma Plant	OIEC Adjustments to Plant in Service
			Acct. 101/106		
1	Plant in Service per PSO at January 31, 2014	\$ 4,298,561,651	OIEC 1.7 (a) Supp2		
2	Add: PSO's Intangible Plant (AMI) at January 31, 2014	\$ 5,166,456	OIEC 1.7 (a) Supp		
3	Add: PSO's AMI Meter Adjustment at January 31, 2014	<u>\$ 10,853,807</u>	OIEC 1.7 (a) Supp		
4	Total Plant in Service at January 31, 2014	\$ 4,314,581,914	C-01, p.3	\$ 4,228,153,805	\$ 86,428,109
5	Accumulated Depreciation per PSO at January 31, 2014	\$ (1,610,610,731)	OIEC 1.7(b) Supp2		
6	Add: PSO's AMI Accumulated Depreciation Adjustment	<u>\$ (2,220,725)</u>	OIEC 1.7(b) Supp2		
7	Total Accumulated Depreciation at January 31, 2014	\$ (1,612,831,456)	OIEC 1.7 (b) Supp	\$(1,596,714,353)	\$ (16,117,103)
8	Net Plant in Service	<u>\$ 2,701,750,458</u>		<u>\$ 2,631,439,452</u>	<u>\$ 70,311,006</u>

PUBLIC SERVICE COMPANY OF OKLAHOMA
 OIEC WORKPAPERS - ADJUSTMENT TO ACCUMULATED DEFERRED INCOME TAXES
 Test Year Ended 07-31-13
 Cause NO. PUD 201300217

Line No.	Description	Plant Balances 1/31/2014	Ref.	PSO Pro Forma Plant	OIEC Adjustments to Plant
1	Accumulated Deferred Tax at January 31, 2014	\$ (842,492,288)	AG 1.18 Supp		
2	Add: Intangible Plant ADIT at January 31, 2014	\$ (1,228,324)	AG1.7, p.16		
3	Add: AMI Meter ADIT at January 31, 2014	<u>\$ (865,450)</u>	AG1.7, p.16		
4	Total Plant in Service at January 31, 2014	<u>\$ (844,586,062)</u>	Sch. B.2	<u>\$ (824,276,775)</u>	<u>\$ (20,309,287)</u>

PUBLIC SERVICE CO.
 OIEC WORKPAPERS - ADJUSTMENT TO FUEL INVENTORY AND STORM REGULATORY ASSET
 Test Year Ended 7-31-13
 Cause NO. PUD 201300217

Line No.	Description	Reference	Fuel Inventories	Prepayments	July 2013 Storm
1	PSO Pro Forma Fuel Inventory	W/P B-05	\$ 19,474,443		
2	PSO Adjustment for Eliminated Oil Inventories	W/P B-3.4	<u>\$ (1,381,154)</u>		
3	Total PSO Pro Forma Balance	Calc.	\$ 18,093,289		
5	Actual Inventory Level at January 31, 2014	OIEC 1.7	<u>\$ 15,734,288</u>		
6	OIEC Adjustments		<u>\$ (2,359,001) (1)</u>		
7	PSO Pro Forma Prepayment Balance	W/P B-05		\$ 111,004,957	
8	Actual Prepayment Level at January 31, 2014	OIEC 1.7(d) Supp Alt1		<u>\$ 105,373,187</u>	
9	OIEC Adjustments	Calc.		<u>\$ (5,631,770) (2)</u>	
10	OIEC Adjustment to Remove 2013 Storm Regulatory Asset	W/P B-3.5			<u>\$ (10,000,000) (3)</u>

FN 1 Adjustment to update Fuel Inventory to the 6-month post test year cutoff.

FN 2 Adjustment to update Prepayments to the 6-month post test year cutoff.

FN 3 Adjustment to remove the storm damage regulatory asset from rate base.

PUBLIC SERVICE CO.
 OIEC WORKPAPERS - ADJUSTMENT TO PREPAID PENSION
 Test Year Ended 07-31-13
 Cause NO. PUD 201300217

Line No.	Description	Ref.	Amount
1	PSO Prepaid Pension Balance Included in Rate Base	Exh RWH-2	\$ 104,227,255
2	ADFIT Associated with Prepaid Pension Balance	35%	<u>\$ (36,479,539)</u>
3	Prepaid Pension Balance in Rate Base net of ADIT	Calc.	\$ 67,747,716
4	OIEC Adjustment to Remove Prepaid Pension Balance from Rate Base		\$ (67,747,716)
5	13-Month Average Included in PSO's Pro Forma Rate Base	OIEC 13-6a	\$ 67,747,716
6	Expected Return on Pension Asset	Exh RWH-2	<u>6.50%</u>
7	OIEC Adjustment to Include Return on Prepaid Pension Balance	Calc.	<u>\$ 4,403,602</u>

PUBLIC SERVICE CO.
OIEC WORKPAPERS - ADJUSTMENT TO INCENTIVES EXPENSE
Test Year Ended 07-31-13
Cause NO. PUD 201000050

Line No.	(a) Description	(b) Reference	(c) AEPSC Annual Incentive Plan	(d) PSO Annual Incentive Plan	(e) AEPSC Long-Term Plan	(f) PSO Long-Term Plan	(g) Total Test Year Incentives
1	Total Test Year Incentives Expense		\$ 6,812,712	\$ 7,614,605	\$ 4,890,989	\$ 1,063,735	\$ 20,382,041
2		Source	[AG 3.8 AltI2]	[AG 3.9 AltI2]	[AG 3.8 AltI2]	[AG 3.9 AltI2]	
4	PSO Pro Forma Adjustment		\$ (2,679,816)	\$ (3,510,612)	\$ (1,983,779)	\$ (416,828)	\$ (8,591,035)
5		Source	[Griffen pp 8-9]	[WP H-2.7]	[Griffen pp 8-9]	[WP H-2.7]	
7	Incentives Included in Pro Forma Operating Expense		\$ 4,132,896	\$ 4,103,993	\$ 2,907,210	\$ 646,907	\$ 11,791,006
8		Source	[AG 3.11 AltI2]	[AG 3.9 AltI1]	[AG 3.11 AltI2]	[AG 3.9 AltI1]	
11	OIEC Adjustment to Pro Forma Incentive Expense						Adjustments
13	AEP Annual Incentives in Pro Forma Expense	Ln 7, Col. (c)	\$ 4,132,896				
15	PSO Annual Incentives in Pro Forma Expense	Ln 7, Col. (d)	\$ 4,103,993				
17	Total Annual Incentives in Pro Forma Expense		\$ 8,236,889	50% Disallowed	Annual Incentive Adjustment		\$ (4,118,445)
20	AEP Long-Term Incentives in Pro Forma Expense	Ln 7, Col. (e)	\$ 2,907,210				
22	PSO Long-Term Incentives in Pro Forma Expense	Ln 7, Col. (f)	\$ 646,907				
24	Total Long-Term Incentives in Pro Forma Expense		\$ 3,554,117	100% Disallowed	Long Term Incentive Adjustment		\$ (3,554,117)
27	OIEC Adjustment for Capitalized Incentives						
29	Incentive Compensation Imbedded in Plant Accounts		PSO - STIP	AEPSC - STIP	PSO - LTIP	AEPSC-LTIP	
30		SEE MG-2 in PUD 08-144					
31	2000		\$ 489,533				
32	2001		\$ 993,277				
33	2002		\$ 1,412,880	\$ 439,645			
34	2003		\$ 1,201,058	\$ 369,578			
35	2004		\$ 982,889	\$ 784,662			
36	2005		\$ 3,008,757	\$ 1,586,409			
37	2006		\$ 2,974,343	\$ 1,794,873			
38	2007		\$ 2,892,262	\$ 2,832,735			
39	2008		\$ 355,094	\$ 375,889			
40	2009		\$ 386,977	\$ 402,440			
41	2210	OIEC 1.1 - 1.4	\$ 1,897,707	\$ 924,572	\$ 123,521	\$ 206,613	
42	2011		\$ 2,775,284	\$ 644,572	\$ 443,731	\$ 354,397	
43	2012		\$ 2,677,904	\$ 1,970,358	\$ 359,607	\$ 394,996	
44	2013		\$ 2,890,150	\$ 1,984,276	\$ 317,779	\$ 583,056	
45			\$ 24,938,115	\$ 14,110,009	\$ 1,244,638	\$ 1,539,062	
47	Percentage Disallowed		50%	50%	100%	100%	
49	OIEC Adjustment for Capitalized Incentives		\$ (12,469,058)	\$ (7,055,005)	\$ (1,244,638)	\$ (1,539,062)	\$ (22,307,762)
52	OIEC Adjustment for Labor Attendant Costs Related to Disallowed Incentives						
54	PSO Short-Term Incentives	OIEC 1.5 Alt 1				\$ 4,103,993	
55	Disallowed Percentage	OIEC 1.5 Alt 1				50.00%	
56	FICA Percentage	OIEC 1.5 Alt 1				7.27%	\$ (149,180)
57	Savings Plan Loading Rate	OIEC 1.5 Alt 1				3.80%	\$ (77,976)
58	OIEC Adjustment to Remove Labor Attendant Costs for Disallowed Incentives						\$ (227,156)

PUBLIC SERVICE CO.
OIEC WORKPAPERS - ADJUSTMENT TO SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN EXPENSE
Test Year Ended 07-31-13
Cause NO. PUD 201300217

Line No.	Description	Reference	Total SERP in Pro Forma Expense
1	Supplemental Pension Costs in Pro Forma Operating Expense	[OIEC 4.1]	\$ 359,450
2	OIEC Adjustment to Remove Supplemental Executive Retirement Costs from Rates		<u>\$ (359,450)</u>

PUBLIC SERVICE CO.
 OIEC WORKPAPERS - ADJUSTMENT TO PSO LABOR EXPENSE
 Test Year Ended 7-31-13
 Cause NO. PUD 201300217

Line No.	Description	Ref.	Amount
1	Annualized Payroll at January 31, 2014	AG 2.13 Supp 2, Att 1	\$ 74,949,635
2	Payroll Expense Factor		70.98%
3	Labor Expense Based on January 2014 Pay Levels		\$ 53,199,251
4	PSO Pro Forma Labor Expense	WP H-04.4	<u>\$ 53,925,124</u>
5	OIEC Adjustment to Reflect Labor Expense at 6-Month Levels		<u>\$ (725,873)</u>
6	Effective FICA Rate	W/P H-02.8	7.27%
5	OIEC Adjustment for FICA Tax Associated with Labor Adjustment		<u>\$ (52,771)</u>

PUBLIC SERVICE CO.
OIEC WORKPAPERS - ADJUSTMENT TO AEPSC LABOR
 Test Year Ended 7-31-13
 Cause NO. PUD 201300217

AEPSC Payroll Charged to PSO by Pay Period for Aug 2013 - December 2013

Source	Pay Date	Regular	Overtime	Non-Productive	Incentive	Other	Grand Total	Empl Count	
AG2.20 Att2 ↓	2013-08-09	2,571,101.21	1,105,492.59	441,443.99	333,095.83	39,438.16	4,490,571.77	2,152	
	2013-08-23	2,746,513.84	324,856.08	484,928.12	357,370.36	8,053.45	3,921,721.86	2,219	
	2013-09-06	2,778,101.35	262,676.03	488,900.91	333,000.47	77,239.52	3,939,918.27	2,252	
	2013-09-20	2,547,231.32	336,030.66	451,684.28	739,759.32	4,006.96	4,078,712.52	2,199	
	2013-10-04	2,797,279.59	369,026.53	490,983.78	332,823.18	8,286.07	3,998,399.15	2,196	
	2013-10-18	2,850,465.30	546,012.40	522,782.86	2,003,470.44	4,677.55	5,927,408.54	2,189	
	2013-11-01	2,792,264.77	389,008.61	510,625.49	710,644.51	86,080.41	4,488,623.80	2,210	
	2013-11-15	2,832,856.54	410,753.59	532,798.78	710,405.56	11,463.00	4,498,277.47	2,194	
	2013-11-29	2,826,572.53	360,723.84	560,802.50	926,486.19	11,298.26	4,685,883.32	2,191	
	2013-12-13	2,097,598.54	482,370.67	451,147.13	1,010,397.85	5,181.37	4,046,695.56	2,099	
	2013-12-27	2,689,220.92	778,519.71	576,646.37	2,020,879.43	3,960.18	6,069,226.61	2,113	
	AG 6.2 Att2 ↓	2014-01-10	1,447,487.24	1,132,138.67	301,558.14		31,488.38	2,912,672.44	1,849
		2014-01-24	2,905,238.90	355,454.54	603,795.76	664,934.24	22,476.24	4,551,899.67	2,122

OIEC Payroll Annualizations of AEPSC Regular Pay at 6-Month Cutoff Levels

Line	Description	Reference	Based on the Following Payroll Periods		
			Jan '14	Dec '13 thru Jan '14	Nov '13 thru Jan '14
1	Annualized Payroll at January 2014	above	56,585,440	59,407,046	65,338,889
2	Test Year Payroll Costs	AG 2.19 Att2	68,596,356	68,596,356	68,596,356
3	Adjustment to Reduce Test Year to 6-Month Level	calc.	(12,010,916)	(9,189,310)	(3,257,467)
4	Expense Percentage (70.98%) [H-04.4]		(8,525,348)	(6,522,572)	(2,312,150)
5	Adjustment to Reverse PSO Requested Increase		(798,429)	(798,429)	(798,429)
6	Adjustment to Annualize Payroll at 6-Month Level		(9,323,777)	(7,321,001)	(3,110,579)
7	OIEC AEPSC Payroll Annualization Adjustment				<u>(3,110,579)</u>
8	Payroll Tax Percentage	W/P H-2.08			7.27%
9	OIEC AEPSC Payroll Annualization Adjustment for Payroll Taxes				<u>\$ (226,139)</u>

PUBLIC SERVICE CO.
OIEC WORKPAPERS - ADJUSTMENT TO RATE CASE EXPENSE
Test Year Ended 7-31-13
Cause NO. PUD 201300217

Ln No	Description	Payee	Estimated Costs	Cost Incurred thru 1/31/14	Remaining Estimated Cost
			REF --> W/P H.13.2	PUD JS1.5 Att 1	
1	Outside Consultants:				
2	ROE Witness	C H Guernsey & Company	\$ 200,000	\$ 63,475	\$ 136,525
3	Demolition Study Witness	Sargent & Lundy LLC	150,000	74,054	75,946
4	Lead Lag Study	Expergy	20,000	35,388	(15,388)
5	Depreciation Witness	Gannett Fleming Inc	75,000	38,081	36,919
6	Total Outside Consultants		<u>\$ 445,000</u>	<u>\$ 210,999</u>	<u>\$ 234,001</u>
7					
8	Legal:				
9	Outside Counsel	White Coffey & Fite	200,000	65,232	134,768
10	Total Legal		<u>\$ 200,000</u>	<u>\$ 65,232</u>	<u>\$ 134,768</u>
11					
12	Company Expenses:				
13	Employee Travel and Expense	various	50,000	415	49,585
14	Temporary Labor	Plus Group, Manpower	10,000	4,358	5,642
15	Postage, Fed-Ex, Copying	various	15,000		15,000
16	Transcripts		15,000		15,000
17	Notice	Oklahoma Press Association	5,000		5,000
18	Total Company Expenses		<u>\$ 95,000</u>	<u>\$ 4,773</u>	<u>\$ 90,227</u>
19					
20	Total		<u>\$ 740,000</u>	<u>\$ 281,004</u>	<u>\$ 458,996</u>
21					
22	Deferred Rate Case Expense (PUD 201000050)		(248,367)		
23					
24	Total Requested Rate Case Costs		<u>\$ 491,633</u>		
25					
26	Requested Amortization Period		18		
27					
28	Amount requested in Pro Forma Rates		<u>\$ 327,755</u>		
29					
30	OIEC Proposed Adjustment to Rate Case Expense				
31					
32	Total Requested Rate Case Costs		\$ 491,633		
33					
34	Additional Deferred Rate Case Expense through July 2014 (1)		<u>(428,435)</u>		
35					
36	Total Requested Amount after 20100050 Amortization (2)		63,198		
37					
38	Less inappropriate Amount Requested for ROE Witness (3)		<u>(125,000)</u>		
39					
40	Amount Remaining to be Amortized		0.00		
41					
42	OIEC Adjustment to Remove Requested Amortization		<u>\$ (327,755)</u>		

NOTES:

- (1) The additional year of deferred rate case expense (from PUD 10-50) from the end of the test year to the beginning of the rate-effective period will cover most of the requested rate case costs in this case.
- (2) The remaining requested rate case costs above the additional accumulation of over-recovered (deferred) rate case costs from PUD 10-50 will likely not be entirely spent. The schedule above shows that at the end on January only \$281,004 of the requested \$740,000 had been spent.
- (3) At least \$125,000 of the requested cost for an ROE witness is excessive and inappropriate. The current going rate for an ROE witness is between \$25,000 and \$50,000, with utilities paying the higher end of that range. Even grossing up the higher end of the reasonable range by 50%, only results in \$75,000. Ratepayers should not be required to pay extreme above-market rates for a witness that is testifying mainly on behalf of shareholders.

PUBLIC SERVICE CO.
 OIEC WORKPAPERS - ADJUSTMENTS TO DEPRECIATION EXPENSE
 Test Year Ended 07-31-13
 Cause NO. PUD 201300217

Line No.	Description	Ref.	Amount
1	PSO Requested Depreciation Expense Using Proposed Rates and Pro Forma Plant Balance	W/P H-02.24	\$ 115,750,496
2	OIEC Depreciation Expense Using Existing Rates and Plant Balances at January 31, 2014	EC 1.7(g) Apr Supp Att1 Sch I-01 Existing, p. 6	<u>\$ 89,125,182</u>
3	2014		<u>\$ (26,625,314)</u>
4	RECAP: Actual Increase Needed to Apply Existing Depreciation Rates to Actual Plant Balances at January 31, 2014		
		Plant Balance	Depreciation Expense
5	<u>Test Year Plant w/ existing rates (W/P H2.24)</u>		
6	Production	\$ 1,365,435,869	\$ 21,936,785
7	Transmission	\$ 725,207,790	\$ 13,744,068
8	Distribution	\$ 1,914,534,340	\$ 45,002,084
9	General	\$ 147,698,553	\$ 4,562,534
10	Intangible	<u>\$ 4,152,876,552</u>	<u>\$ 85,245,471</u>
11	<u>6-Month Plant Balances with Existing Rates (OIEC 1.7 Supp Att1)</u>		
12	Production	\$ 1,396,214,451	\$ 22,699,866
13	Transmission	\$ 731,312,344	\$ 14,141,312
14	Distribution	\$ 1,984,016,692	\$ 47,700,374
15	General	\$ 160,005,026	\$ 4,583,629
16	Intangible	<u>\$ 4,271,548,513</u>	<u>\$ 89,125,181</u>
17			
18	Actual Increase needed to Apply Existing Rates to Plant Balances at January 31, 2014		<u>\$ 3,879,710</u>
PROOF:			
19	PSO Depreciation Adjustment to Apply Proposed Rates to Pro Forma Plant Balances	W/P H.2.24 and H Adj No 28	\$ 30,505,024
20	OIEC Adjustment to Apply Existing Depreciation Rates to Plant Balances at January 31, 2014	(Ln 5 Above)	<u>\$ (26,625,314)</u>
21	Remaining Actual Increase Needed to Apply Existing Rates to Plant at January 31, 2014	(RECAP Above)	<u>\$ 3,879,710</u>

Public Service Company of Oklahoma
COST OF CAPITAL
 Test Year Ended July 31, 2013
 Cause No. PUD 201300217

LINE	DESCRIPTION	(A) CAPITALIZATION RATIOS	(B) COST OF CAPITAL	(C) WEIGHTED COST OF CAPITAL	(D) INCOME TAX GROSS UP FACTOR	(E) WEIGHTED COST OF CAPITAL WITH INCOME TAXES
<u>PSO Requested Cost of Capital:</u>						
1	LONG TERM DEBT	51.313%	5.510%	2.830%	1.00000	2.830%
2	PREFERRED STOCK	0.000%	0.000%	0.000%	1.639140	0.000%
3	COMMON STOCK	<u>48.687%</u>	<u>10.500%</u>	<u>5.110%</u>	<u>1.639140</u>	<u>8.376%</u>
4	TOTAL	<u><u>100.00%</u></u>		<u><u>7.94%</u></u>		<u><u>11.206%</u></u>
<u>OIEC Recommended Cost of Capital:</u>						
5	LONG TERM DEBT	51.313%	5.510%	2.830%	1.00000	2.830%
6	PREFERRED STOCK	0.000%	0.000%	0.000%	1.639140	0.000%
7	COMMON STOCK	<u>48.687%</u>	<u>9.250%</u>	<u>4.500%</u>	<u>1.639140</u>	<u>7.376%</u>
8	TOTAL	<u><u>100.00%</u></u>		<u><u>7.33%</u></u>		<u><u>10.206%</u></u>