

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

**IN THE MATTER OF THE APPLICATION)
OF OKLAHOMA GAS AND ELECTRIC)
COMPANY FOR AN ORDER OF THE)
COMMISSION AUTHORIZING) CAUSE NO. PUD 200800398
APPLICANT TO MODIFY ITS RATES,)
CHARGES AND TARIFFS FOR RETAIL)
ELECTRIC SERVICE IN OKLAHOMA)**

**RESPONSIVE TESTIMONY
OF
MARK E. GARRETT**

REVENUE REQUIREMENT ISSUES

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

June 22, 2009

**Prepared Responsive Testimony of Mark E. Garrett
June 22, 2009
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 First National Center, Suite 1400
3 West, 120 North Robinson, Oklahoma City, Oklahoma 73102.

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 Stephen F. Austin State University and
15 the University of Texas at Arlington and Pan American. I received my juris doctorate
16 degree from Oklahoma City University Law School and was admitted to the Oklahoma
17 Bar in 1997. I am a Certified Public Accountant licensed in the States of Texas and
18 Oklahoma with a background in public accounting, private industry, and utility
19 regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily
20 audited financial institutions in the State of Texas. In private industry, as controller for a
21 mid-sized (\$300 million) corporation in Dallas, I managed the Company's accounting

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

8
9 **Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THIS COMMISSION**
10 **AND IN OTHER PROCEEDINGS DEALING WITH COST-OF-SERVICE AND**
11 **OTHER RATEMAKING ISSUES?**

12 A: Yes, they have. A more complete description of my qualifications and a list of the
13 proceedings in which I have been involved are attached to this testimony.

14
15 **Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?**

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

17
18 **Q: WHO IS OIEC?**

19 A: OIEC is an association consisting principally of a diverse group of Oklahoma processing
20 and manufacturing industries which is involved in regulatory and legislative matters
21 primarily involving natural gas and electric power.

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

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

11
12 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

13 A: The purpose of my testimony is to address various revenue requirement issues identified
14 in OG&E's rate case application and to provide the Commission with recommendations
15 for the resolution of these various issues. I also sponsor the OIEC Accounting Exhibits
16 where the impact of the OIEC revenue requirement recommendations is set forth.
17 OIEC's adjustments reduce OG&E's requested rate increase of \$110.3 million by \$97.7
18 million, and result in a recommended rate increase of \$11.6 million:

19	Rate Increase Proposed by OG&E	\$110,325,330
20	OIEC Adjustments	<u>\$ 97,741,603¹</u>
21	Rate Increase Proposed by OIEC	<u>\$ 12,583,727</u>

¹ These recommended adjustments do not reflect OIEC's rate design recommendations which will result in further reductions to the rate increase proposed for the industrial customer classes.

II. RATE BASE ADJUSTMENTS

II. A. PLANT/ACCUMULATED DEPRECIATION – (Six-Month Post TY Adjustment)

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

4 A. Yes. My adjustment updates the Plant in Service and Accumulated Depreciation
5 accounts through March 31, 2009. In Oklahoma, the Commission is required by law
6 (Title 17 § 284) to give effect to known and measurable changes that occur within six
7 months of test year end. In this application, the six month cut-off period for post test
8 year adjustments is March 31, 2009.

9

10 **Q: HOW IS YOUR ADJUSTMENT TO REFLECT ACTUAL INVESTMENT**
11 **LEVELS AT MARCH 31, 2009 CALCULATED?**

12 A: In general, the adjustment is calculated by comparing the Company's requested level of
13 Plant in Service and Accumulated Depreciation to the actual balances in these accounts
14 at March 31, 2009. The Company's requested level for plant investment includes actual
15 Plant in Service balances at test year end, plus the cost of construction projects expected
16 to be completed and in service within six months after test year. My adjustment picks up
17 the actual plant balances at March 31, 2009. Thus, all plant actually completed and in
18 service within six months of test year end are properly included in rate base. Also, all

1 off-setting decreases in the plant investment levels – in effect, all changes in the
2 Accumulated Depreciation accounts – are recognized as well.
3

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

5 A: Yes. In ONG's recent rate case, Cause No. PUD 200400610, the ALJ adopted this
6 approach, no party appealed the recommendation, and the Commission accepted and
7 approved the ALJ's recommendation. In that proceeding, after a hearing on the merits,
8 the ALJ updated ONG's Plant in Service and Accumulated Depreciation balances
9 through the six month period following test year end. Projects still in the CWIP
10 accounts at that time were specifically excluded. Also, in OG&E's last rate case, PUD
11 200500151, the Commission again updated the Plant and Accumulated Depreciation
12 balances to six months after test year end and appropriately excluded CWIP on the books
13 at that time. Also, in PSO's last two rate cases, Cause No. PUD 200600285 and Cause
14 No. PUD 200800144, the Commission used this approach.
15

16 **Q: HAVE YOU REVIEWED OG&E'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 before new rates go into effect. However, the CWIP
21 adjustment proposed by the Company is not necessary when the Plant in Service and
22 Accumulated Depreciation accounts are updated to the 6-month post-test-year cutoff

1 date. By updating the plant accounts to the March 31, 2009 cutoff date, all CWIP
2 projects completed by that time are included in the adjustment. When the Commission
3 adopted this approach in the recent ONG, OG&E and PSO cases, the Commission
4 updated the Plant in Service balances and the Accumulated Depreciation balances to 6-
5 month cutoff and appropriately excluded CWIP on the books at that time. This treatment
6 has the effect of including in rate base all CWIP projects actually complete and in
7 service within the six month post test year period.

8
9 **Q: HOW IS CWIP GENERALLY TREATED FOR RATEMAKING PURPOSES**
10 **WHEN THE TEST YEAR IS NOT UPDATED?**

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

16
17 **Q: WHY IS THIS THE GENERALLY ACCEPTED TREATMENT OF CWIP?**

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

1 utility service, the invested capital along with its accrued return is transferred to rate
2 base.

3

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

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

13

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

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

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

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

19
20 **Q: IS YOUR PROPOSED TREATMENT – THAT WAS ACCEPTED IN THE**
21 **RECENT ONG, OG&E AND PSO RATE CASES – 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 six month post test year period.

5
 6 **Q: WHAT ADJUSTMENTS TO PRO FORMA RATE BASE ARE NEEDED TO**
 7 **REFLECT ACTUAL NET INVESTMENT LEVELS AT MARCH 31, 2009?**

8 A: The OIEC’s adjustments to the Company’s pro forma rate base are set forth below. The
 9 detailed calculations reflecting OG&E’s actual investment levels at 3-31-09 are shown in
 10 the OIEC Accounting Exhibit Schedule B-3 (filed contemporaneously with this
 11 testimony). The impact of these adjustments is set forth below.

12

OIEC Adjustments to Update Plant and Accumulated Depreciation to 3-31-09				
	Description	OG&E Plant (Includes CWIP)	OIEC Plant (At 3-31-09)	OIEC Adjustment
1	Plant in Service	\$6,395,655,492	\$6,406,762,945	\$11,107,453
2	Accumulated Depreciation	\$2,654,035,727	\$2,713,244,609	(\$59,208,882)
3	Total (Decrease in Rate Base)			(\$48,101,429)

II. B. ADIT – (Six-Month Post Test Year Adjustment)

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 3-31-09 levels. This adjustment is necessary to give effect to the known
5 and measurable increase in the deferred tax balances that occurred within six months of
6 test year end. When additions to the investment levels in Plant in Service are recognized
7 through the six month period following test year end, off-setting decreases in the
8 investment levels related to Plant in Service such as Accumulated Depreciation and
9 Accumulated Deferred Income Tax must be recognized as well. This adjustment has
10 been consistently accepted by the Commission in recent rate case proceedings, and is
11 consistent with Oklahoma law (Title 17 § 284).

12
13 **Q: WHAT ADJUSTMENT IS NECESSARY TO UPDATE THE ACCUMULATED**
14 **DEFERRED INCOME TAX BALANCES TO THE 3-31-09 LEVELS?**

15 A: The necessary adjustment is set forth below and can be seen in the OIEC Accounting
16 Exhibit at Schedule B-3.

17
18

OG&E Requested ADIT Balance at Test Year End (Schedule B2)	\$714,946,985
ADIT Balance at March 31, 2009	<u>\$708,895,672</u>
OIEC Adjustment to Reflect ADIT at March 31, 2009	<u>\$ 6,051,313</u>

19
20

II. C. INVENTORY ACCOUNTS – (Six-Month Post Test Year Adjustment)

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

3 A: I have updated the Company's inventory levels and the prepaid asset account balance to
4 March 31, 2009.

5

6 **Q: WHAT ADJUSTMENTS ARE NEEDED TO REFLECT THE FUEL**
7 **INVENTORY AND CUSTOMER DEPOSIT LEVELS AT MARCH 31, 2009?**

8 A: The adjustments are shown in the table below and in the OIEC Accounting Exhibit at
9 Schedule B-3.

TABLE – OIEC Adjustments to Update Inventory Levels to 3-31-09				
	Description	Coal Inventories	Materials & Supplies	Prepayments
1	Level at Test Year End	\$29,871,247	\$67,804,355	(\$900,831)
2	Level at March 31, 2009	\$27,378,551	\$71,583,012	\$858,133
3	OIEC Adjustments	(\$2,492,696)	\$3,778,657	\$1,758,964

II. D. PENSION COSTS IN RATE BASE

1 **Q: WHAT ISSUES HAVE YOU IDENTIFIED WITH RESPECT TO PENSION**
2 **COSTS IN RATE BASE?**

3 A: The Company has included three separate balances for pension costs in rate base. These
4 pension cost balances include: (1) the prepaid pension account, (2) the deferred pension
5 expense account, and (3) the accrued SFAS 158 pension cost account. In this section of
6 testimony, I will address each of these pension cost accounts and explain why each
7 account is not includible for ratemaking purposes. With respect to pension costs,
8 ratepayers are responsible for funding the Company's net periodic pension expense and
9 nothing more. The Company's discretionary excess contributions to the plan, the over
10 and under recovery of pension expense and the over and under funding status of the
11 pension plan are not costs for which ratepayers are responsible. As such, these costs
12 should not be included in rate base.

1. Prepaid Pension Account

14
15
16 **Q: WHAT ADJUSTMENT ARE YOU PROPOSING TO THE COMPANY'S**
17 **PREPAID PENSION BALANCE IN PRO FORMA RATE BASE?**

18 A: I am proposing to reduce OG&E's rate base by the balance in this account.
19

1 **Q: WHAT DOES THE BALANCE IN THE PREPAID PENSION ACCOUNT**
2 **REPRESENT?**

3 A: In general terms, the balance in this account is the accumulated difference between the
4 Statement of Financial Accounting Standards No. 87 (“SFAS 87”) accrued pension costs
5 each year and the actual contributions made by the Company to the pension fund. When
6 there is a debit balance in the account, as is the case here, the Company has been
7 contributing more to the fund than its SFAS 87 calculated cost levels.

8
9 **Q: ARE THESE CONTRIBUTIONS MANDATORY?**

10 A: No, contributions in excess of the SFAS 87 cost levels are discretionary payments.
11 Since the contributions are discretionary they are not a *necessary cost of providing*
12 *electric service* and as such should not be included in rate base.

13
14 **Q: WHY ARE YOU NOT RECOMMENDING A COST-OF-MONEY RETURN FOR**
15 **THIS BALANCE AS YOU DID IN OG&E’S LAST RATE CASE?**

16 A: In the last rate case, I recommended a cost-of-money return on the balance because
17 ratepayers had received a benefit from the contributions in the form of lower SFAS 87
18 expense levels. Now, it is uncertain whether ratepayers will receive any benefit from the
19 Company’s contributions, in light of the significant losses experienced in the stock
20 market shortly after the Company’s excess contributions were made.² The Company

² The balance in the prepaid pension account went from 0 to \$31 million in the 6-month period leading up to the end of the test year, September 2008. The stock market decline occurred the following month, October 2008.

1 would have to show that ratepayers benefited from the Company making excess
2 contributions before the stock market decline rather than after.

3
4 **2. Deferred Pension Expense – Regulatory Asset Adjustment**

5
6 **Q: ARE THERE OTHER PENSION ISSUES?**

7 A: In the Company's last rate case, the Commission authorized the Company to track the
8 over and under recovery of its annual pension expense in a regulatory asset/liability
9 account. Specifically, the order stated:

10 w. **Tracking Mechanism for Pension Expense.** The Referee adopts Staff's
11 proposal and authorizes OG&E to set up regulatory asset and liability
12 accounts to track the changes in pension expense. However, as
13 recommended by Staff, the Commission will decide what level will be
14 allowed or disallowed in future rate cases on a case-by-case basis.

15 From the last rate case through the end of the test year, the Company's actual pension
16 expense has exceeded the amount included in rates by \$17,157,838.³ The Company
17 seeks recovery of this balance over a 2-year period. The Company also seeks to include
18 the entire balance in rate base. With this treatment the Company will earn a full rate
19 base return on the entire balance during the rate effective period.

20
21 **Q: DO YOU AGREE WITH THE COMPANY'S PROPOSED TREATMENT?**

22 A: No. I found nothing in the Commission's prior order that authorized a return on the
23 deferred pension costs. I believe that the prior order allows the Company to defer and

³ According to W/P B-3-10

1 recover these costs in rates but does not also allow a return on the balance during the
2 recovery period. Further, I believe a return on this type of account would be highly
3 inappropriate. By allowing the Company to defer its under-recovery of pension costs
4 between rate cases, the Commission effectively shifted the Company's risk for these
5 costs to the ratepayers without any corresponding decrease in the Company's allowed
6 return on equity. In my opinion, staff's recommendation to shift the risk of pension
7 under-recoveries to ratepayers without a corresponding adjustment to the return
8 component was improper. However, to allow the Company to earn a return on the
9 deferred balance would only compound the inequity. It is enough that the Commission
10 shifted the risk of pension cost under-recoveries to the rate payers without compensation.
11 Adding a return to the balance at this point would only exacerbate the problem.

12
13 **Q: WHAT IS YOUR RECOMMENDATION?**

14 A: I recommend that the Company be allowed to recover its deferred pension costs in rates,
15 because that was the treatment ordered in the prior case. However, the order was silent
16 as to whether the Company should also be allowed to earn a return on this regulatory
17 asset balance. Therefore, I recommend the Commission not allow the Company to
18 include the deferred pension balance in rate base.

19
20 **3. SFAS 158 – Accounting for Defined Pension Plans**

21
22 **Q: ARE THERE OTHER ISSUES RELATED TO PENSION COSTS?**

1 A: Yes. In this case the Company has for the first time proposed including its accrued
2 pension asset and liability accounts in rate base. These accounts have been on the books
3 for many years and never included in rate base. However, in 2006, the Financial
4 Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard
5 (SFAS) 158, which changed the balance sheet presentation for companies with defined
6 benefit pension plans.⁴ OG&E points to this accounting change as the basis for it now
7 including these accounts in rate base. However, the bottom-line difference that comes
8 out of the new pronouncement is that the pension balance sheet accounts now include
9 and show the *funded status* (plan assets minus obligations) of a company's pension plan,

4 Statement of Financial Accounting Standards (SFAS) 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—An Amendment of FASB Statements No. 87, 88, 106, and 132(R)*, was issued September 2006. This pronouncement significantly changes the balance-sheet reporting for defined benefit pension plans. Before SFAS 158, many events, such as actuarial gains and losses, were not recognized on the balance sheet. As a result, a plan's funded status (plan assets minus obligations) was rarely reported on the balance sheet. SFAS 158 requires companies to report their plans' funded status as either an asset or a liability on their balance sheets, which will cause reported pension liabilities to rise significantly. Although SFAS 158 also applies to postretirement benefit plans other than pensions and to not-for-profit entities, the focus below is on for-profit businesses with defined benefit pension plans.

Under SFAS 87, prepaid or accrued pension cost, which is the net of a firm's pension assets, liabilities, and unrecognized amounts, is reported on the balance sheet. SFAS 158 arguably improves financial reporting by more clearly communicating the funded status of defined benefit pension plans. Previously, this information was reported only in the detailed pension footnotes.

Under SFAS 158, companies with defined benefit pension plans must recognize the difference between the plan's projected benefit obligation and its fair value of plan assets as either an asset or a liability. The projected benefit obligation is the actuarial present value of the benefits attributed by the pension plan benefit formula for services already provided. As a result, the complex and conceptually unsound "minimum pension liability" rules, which are used when the accumulated benefit obligation is less than the fair value of pension plan assets, has been eliminated. (The accumulated benefit obligation is similar to the projected benefit obligation but does not include expected future salary increases in the calculation of the present value of actuarial benefits.) In addition, the unrecognized prior service costs and actuarial gains and losses that were previously relegated to the footnotes are now recognized on the balance sheet, with an offsetting amount in accumulated other comprehensive income under shareholders' equity.

SFAS 158 does not change the computation of periodic pension cost, which remains a function of service cost, interest cost, expected return on pension plan assets, and amortization of unrecognized items. It does, however, impact the reporting of comprehensive income. Specifically, actuarial gains or losses and prior service costs that arise during the period are recognized as components of comprehensive income. In addition, the amortization of actuarial gains or losses, prior service costs, and transition amounts recognized before implementing SFAS 158 require a reclassification adjustment to comprehensive income. Shaw, Kenneth W., New Accounting Rules for Defined Benefit Pension Plans, The CPA Journal Online (March 2008).

1 whereas before, the funded status information was generally reported only in the
 2 financial statement footnotes. Clearly, this change in accounting presentation cannot be
 3 used to justify including the over or under funded status of a pension plan in rates.
 4 Pension plans have always been over and under funded and these differences have never
 5 been included in rates. The mere fact that the funded status of a pension plan is now
 6 reported on the balance sheet rather than in the footnotes does not change the ratemaking
 7 treatment of these costs.

8
 9 **Q: WHAT ADJUSTMENTS ARE YOU PROPOSING?**

10 A: I am proposing to remove (1) the prepaid pension balance, (2) the deferred pension costs,
 11 (3) the accrued pension asset and liability accounts, and (4) the accumulated deferred tax
 12 associated with each of these removed items. The necessary adjustments are set forth
 13 below and in the OIEC Accounting Exhibit at Schedule B-3.

OIEC Adjustment to Remove Pension Accounting from Rate Base					
Ln	Description	Source	Balance	ADIT	Net Adj.
1	Prepaid Pension Asset	W/P B-5	\$ 31,817,551		
2	Deferred Pension Asset	W/P B-3-10	\$ 17,157,838		
3	SFAS 158 Accrued Pension	W/P B-3-10	\$162,393,812		
4	Total Pension Assets		\$211,369,201	(\$74,981,938)	\$136,387,263
5	Accrued Pension Obligation	Sch B-2	(\$108,842,925)	\$32,156,216	(\$76,686,709)
6	Net OIEC Adjustment to Remove Pension Costs from Rate Base				\$ 59,700,554

1 **Q: DO YOU HAVE ANY FURTHER RECOMMENDATIONS REGARDING**
2 **PENSION COSTS?**

3 A: Yes. The treatment of pension accounting in rate base is not consistent among the
4 utilities in Oklahoma. For example, PSO does not include its accrued pension asset and
5 liability accounts in rate base but OG&E is seeking to include these accounts in rate base
6 in this application. PSO was not provided a tracking account for its over and under
7 recoveries of pension expense but OG&E was provided such a mechanism for its costs.
8 These inconsistent treatments should be reconciled at some point. Also, the Commission
9 should review the new accounting pronouncement for pensions, SFAS 158, to determine
10 how the accounting change should be viewed for ratemaking purposes.

11 To address these issues, I recommend the Commission open a docket to review
12 the ratemaking treatment of pension costs in Oklahoma. This docket should address, at a
13 minimum, the following three issues:

- 14 (1) The Commission should determine the appropriate ratemaking treatment for the
15 SFAS 158 accounts.
- 16 (2) The Commission should determine whether a tracking mechanism is appropriate
17 for pension expense, and whether a tracking approach would warrant an
18 offsetting reduction in ROE.
- 19 (3) The Commission should also investigate the extent to which utilities in this state
20 are offering defined benefit plans as opposed to defined contribution plans, and
21 whether each utility is taking sufficient steps to control retirement costs.

II. E. CASH WORKING CAPITAL

1 **Q: WHAT IS OG&E RECOMMENDING IN THIS CAUSE FOR CASH WORKING**
2 **CAPITAL?**

3 A: The Company is recommending a *negative* cash working capital requirement of
4 approximately \$4.427 million.

5

6 **Q: WHAT IS CASH WORKING CAPITAL?**

7 A: Cash working capital is often defined as the net cash outlay that a utility must furnish to
8 provide service before payment for that service is received from the customers.⁵

9 However, it is common today for a major utility to receive payments from its customers
10 before the various obligations of the company to its vendors and employees that relate to
11 those services become due. This creates a situation where the customers are actually
12 supplying the company with cost-free capital, and a reduction to rate base is appropriate
13 in these situations. A utility company's ability to negotiate large contracts
14 advantageously, coupled with its utilization of sound cash management techniques will,
15 in most situations, produce a negative cash working capital requirement.

16

17 **Q: HOW DOES ONE DETERMINE WHETHER CUSTOMERS OR INVESTORS**
18 **ACTUALLY SUPPLY THE UTILITY'S CASH WORKING CAPITAL?**

19 A: A lead-lag study is the most accurate method available to determine whether the
20 company or the customer actually provides the cash that pays the bills for the day-to-day

⁵ See *Accounting for Public Utilities*, § 5.04.

1 operations of the company. A lead-lag study compares the timing differences between
2 the inflows of cash from revenues and the outflows of cash for operating expenses. The
3 net difference is expressed as a positive cash requirement if the Company is supplying
4 cash to pay its day-to-day operating expenses before payments for these services arrive
5 from customers and as a negative cash requirement if payments from customers actually
6 arrive before the Company is obligated to pay its various expenses. These differences
7 are expressed in the number of days between the time the Company pays its bills and the
8 time the customers remit their payments.

9
10 **Q: ARE YOU PROPOSING ADJUSTMENTS TO OG&E'S RECOMMENDED**
11 **CASH WORKING CAPITAL REQUIREMENT IN THE CURRENT**
12 **PROCEEDING?**

13 A: Yes. OG&E's lead-lag study contains errors that must be corrected. These errors
14 consist of the inclusion of non-cash expense items such as depreciation, deferred taxes
15 and a return on common equity in the calculation. With respect to non-cash items and
16 common equity included in the allowance calculation formula, this Commission has
17 already heard and decided these issues. In ONG's 1991 rate case, Cause No. PUD 1190,
18 at page 111 the final order states with respect to noncash items:

19 The Commission finds, based on the evidence presented and arguments of
20 the parties, that noncash cost of service should not be included in ONG's
21 CWC allowance calculation formula. The Commission finds the
22 arguments of Staff and the AG persuasive on the issue and finds that if
23 noncash cost of service items were included in ONG's CWC allowance
24 formula, ONG's CWC allowance would be overstated.

1 With respect to common equity, the same order states at page 112:

2 The Commission finds, based on the evidence presented and arguments of
3 the parties, that ONG's return on common equity should not be included
4 in ONG's CWC calculation. The Commission finds the arguments of
5 Staff and the AG persuasive on the issue and finds that to include such an
6 item in ONG's CWC would compound ONG's stockholder's equity
7 return and overstate ONG's needed CWC.

8 Also, in OG&E's last rate case, Cause No. PUD 200500151, the Commission excluded
9 depreciation, common equity and deferred taxes from the Company's lead lag study. In
10 its order, the Commission adopted Staff's CWC recommendations.⁶ In its testimony,
11 Staff specifically recommended that non-cash items such as depreciation, common
12 equity, deferred taxes, and investment tax credits be excluded from the lead lag study.⁷
13 The exclusion of these items can be seen in the lead lag study attached to the order at
14 Section E, Schedule 1.

15
16 **Q: IS THIS THE GENERALLY ACCEPTED RATEMAKING TREATMENT OF**
17 **DEPRECIATION EXPENSE IN LEAD-LAG STUDIES?**

18 **A:** Yes. A fundamental principle of the cash working capital allowance is that non-cash
19 expense items such as depreciation, deferred income tax, and return on common equity
20 are excluded from the calculations.⁸ These items are excluded because lead-lag studies
21 are intended to measure the timing differences in the collection and disbursement of
22 cash. Noncash items have no impact on these timing differences. Depreciation is

⁶ See page 87 of Order No. 516261

⁷ Staff's recommendations were outlined in the summary of Mr. Thompson's testimony included at page 81 of the order.

1 referred to as a “noncash” expense because there is no *cash outlay* required when a
2 company records depreciation expense, as there are with “traditional cash” expense
3 items such as payroll, operating expenses, interest and taxes. Moreover, depreciation
4 expense is the mechanism for the “return of” capital to investors. Investors are aware of
5 the timing differences associated with the return of their capital through depreciation
6 recoveries and are compensated through the rate of return they charge for the use of their
7 money. For these reasons, the Commission should continue its current policy of
8 excluding Depreciation Expense from any lead-lag cash working capital study.

9
10 **Q: HOW IS COMMON EQUITY GENERALLY TREATED IN A LEAD-LAG**
11 **STUDY?**

12 A: From time to time, a utility will seek to include the dividends on common stock, or other
13 costs associated with common equity in the lead-lag calculations. These attempts are
14 inappropriate and almost universally rejected, as is the case in this jurisdiction.⁹
15 Common equity is generally excluded from the calculations because the return on
16 common equity is a “noncash” item. In other words, there is not a current cash outlay
17 requirement associated with common equity.

18 In addition, common equity is excluded from the calculations because when
19 equity is returned to the company through rates, funds in the possession of the company
20 are deemed in possession of the owners of the company. At that point, it is up to the
21 owners of the company to decide when and how the funds are either reinvested in the

⁸ The Process of Ratemaking by Leonard Saul Goodman, Volume II, page 829, Public Utility Reports, 1998. Also, see the numerous states cited later in this testimony that follow this approach.

1 company or disbursed among the owners. Ratepayers cannot be held accountable for
2 timing differences associated with the return of common equity once the equity is in the
3 control of the company, since the ultimate disposition of the equity at that time is
4 completely up to the owners of the company and wholly outside the control of
5 ratepayers. Moreover, the capital markets are sufficiently aware of the timing
6 differences associated with the return of capital to the company, and have included the
7 cost of those timing differences in the return component required for common equity. In
8 other words, the cost of equity required in the capital markets (i.e. the ROE) takes into
9 account how capital is returned to the company, including any timing differences
10 associated with its collection from ratepayers and its ultimate disbursement among the
11 owners.

12
13 **Q: IS THE APPROACH UTILIZED BY THE COMMISSION IN PUD 91-1190**
14 **SUPPORTED IN ANY RATEMAKING TREATISE?**

15 A: Yes. The approach used by this Commission is the generally accepted rule. In his
16 treatise, The Process of Ratemaking,¹⁰ Leonard Saul Goodman discusses the working
17 capital allowance at length. In Volume II, page 829, the treatise states the following
18 with respect to non-cash items: “A cardinal principle of the working capital allowance is
19 that it should exclude non-cash expenses, such as depreciation, deferred income taxes,
20 and return on common equity, among others.” Goodman cites cases in Iowa, Utah and

⁹ Oklahoma Corporation Commission, Cause No. PUD200500155, Order No. 516261.

¹⁰ 1998. Public Utility Reports, Inc.

1 Illinois.¹¹ Texas, Arizona, Nevada, Kansas, Utah and Oklahoma, among many others
2 could have been included in his list. With respect to depreciation specifically, Goodman
3 further states: “Depreciation expense must be excluded. Even if there is a lag in
4 recouping investment from the time service is rendered to the time the customer pays for
5 the service, there is no basis for adjusting working capital studies for depreciation.
6 Capital markets are ‘aware of any lag involving depreciation expense recovery,’ and
7 ‘adjust accordingly.’”¹²

8
9 **Q: CAN YOU PROVIDE EXAMPLES OF OTHER LEAD-LAG STUDIES WHERE**
10 **THE CASH WORKING CAPITAL CALCULATION EXCLUDES**
11 **DEPRECIATION AND COMMON EQUITY AS OUTLINED ABOVE?**

12 A: Yes. I was recently involved in two rate cases, one in Oklahoma and one in Nevada,
13 where the treatment outlined above was followed. In Oklahoma, in AEP-PSO’s recent
14 rate case, depreciation expense and return on common equity were specifically excluded
15 from the calculations.¹³ PSO’s presentation was consistent with prior Oklahoma
16 Corporation Commission orders where noncash expense items such as depreciation and
17 return on common equity are excluded from the lead-lag calculations.¹⁴ In Nevada,

¹¹ Re U.S. West Communications, Inc., 152 PUR4th 446, 457 (Iowa UB, 1994); Re West Communications, Inc., 142 PUR4th 1, 13-14 (Utah PSC, 1993); Re Illinois Power Co., 131 PUR4th 1, 19 (Ill.CC, 1992).

¹² Quoting from Re Illinois Bell Tel. Co. 156 PUR4th 121, 222 (Ill.CC, 1994); and see Re Central Ill. Light Co., 159 PUR4th 1, 21-22 (Ill.CC, 1994).

¹³ See Schedule E-1 filed in American Electric Power – Public Service Company of Oklahoma’s application in Cause No. PUD 200800144.

¹⁴ In Oklahoma, the larger gas and electric utilities, Oklahoma Gas & Electric, Public Service Co. of Oklahoma, and Oklahoma Natural Gas Co., all present lead-lag studies in their rate case applications to support either a positive or

1 Nevada Power Company filed a lead-lag study in its current rate case application that
2 does not include depreciation expense and return on common equity.¹⁵ This presentation
3 is consistent with the Nevada commission's treatment of these items in previous rate
4 cases.

5
6 **Q: ARE YOU AWARE OF OTHER JURISDICTIONS THAT FOLLOW THIS**
7 **APPROACH?**

8 A: Yes. My understanding is that the **Kansas** Commission excludes depreciation and
9 common equity in the analysis of cash working capital.¹⁶ I also know that the **Arizona**
10 Corporation Commission addressed these specific issues in Decision No. 69663 in the
11 recent APS rate case, Docket No. E-01345A-05-0816. In that case, APS included
12 depreciation expense in its lead-lag study and excluded interest expense on long-term
13 debt. Both Staff and the Residential Utility Consumer's Office ("RUCO")
14 recommended the opposite treatment for both items. The Arizona Commission reviewed
15 testimony and legal briefs on both issues and provided a thorough analysis in its final
16 order to support its decision that the cash working capital allowance should include
17 interest but not depreciation expense in the analysis. With respect to *depreciation*
18 *expense* the Arizona Commission stated:

19 There is no "cash expense" incurred by APS when it records depreciation.
20 It does not have to find cash to pay itself one month and then pay itself
21 back the next. As pointed out by RUCO, an allowance for cash working

negative cash working capital allowance. In Oklahoma, interest expense on long-term debt is included in the cash working capital calculation while depreciation expense and return on common stock are excluded.

¹⁵ See Schedule G-5, Page 1 of 1, Franklin, filed in Nevada Power's application in Docket No. 08-12002.

¹⁶ See for example, Section 6, Schedule 6-H in the Kansas Gas Service's rate case Docket No. 06-KGSG-1209-RTS and Schedule 16 in the Kansas City Power and Light rate case, Docket No. 06-KCPE-828-R75.

1 capital is to address cash flow timing problems, not “regulatory lag”
2 issues related to earnings. . . . While it may be true that APS needs more
3 cash, artificially increasing cash working capital to increase rate base and
4 thereby operating income, is inappropriate.¹⁷

5 In **Texas**, commission rules specifically exclude all “noncash” items from
6 consideration.¹⁸ The list of “noncash” items includes depreciation, amortization,
7 deferred taxes, prepaid items and return (including interest on long-term debt and
8 dividends on preferred stock).¹⁹ Also, in **Utah**, depreciation, deferred taxes and return
9 on common equity are all excluded from the cash working capital calculations.

10 I know of no state that follows the approach recommended by Mr. Rowlett, and
11 he points to no state that follows his approach.

12
13 **Q: WHAT IS THE BASIC PROBLEM WITH THE COMPANY’S APPROACH?**

14 A: The Company assigns zero lag days to depreciation (and the other non-cash components)
15 based on a premise that rate base is immediately reduced through the recording of
16 depreciation expense each month.²⁰ This premise, of course, is flawed because it
17 assumes that a rate case occurs each month to capture the changes in rate base levels. In
18 reality, rate base only changes when there is a rate case. Sometimes these changes can
19 occur years apart. In truth, the capital markets are aware of any lag involving

¹⁷ Arizona Corporation Commission, Docket No. E-01345A-05-0816, Decision No. 69663, page 8.

¹⁸ §25.231(c)(2)(B)(iii)(IV) (-a-) The lead-lag study will use the cash method; all non-cash items, including but not limited to depreciation, amortization, deferred taxes, prepaid items, and return (including interest on long-term debt and dividends on preferred stock), will not be considered.

¹⁹ The problem with the Texas approach is the mischaracterization of interest expense as a noncash item. Clearly, interest expense is not a noncash expense, since there is a definite current cash outlay obligation associated with the expense. The other expense items in the Texas list, such as depreciation, amortization, deferred taxes and prepaid expenses are in fact noncash expenses that should be excluded.

²⁰ See, for example, the Direct Testimony of Mr. Rowlett at page 27, lines 17 through 22.

1 depreciation expense recovery, and adjust accordingly. The bottom line is that investors
2 are compensated for timing differences in depreciation and common equity recoveries
3 through the cost they charge for capital, in effect, the returns required in the market for
4 debt and common equity.

5
6 **Q: WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION**
7 **REGARDING THE CASH WORKING CAPITAL CALCULATIONS TO BE**
8 **USED?**

9 A: I recommend that the Commission continue its practice of excluding depreciation, and
10 return on common equity from the cash working capital calculations. These items
11 represent the return on and return of invested capital to the owners of the company.
12 With respect to depreciation, the capital markets are aware of the regulatory lag involved
13 with depreciation recoveries and have adjusted the cost of capital accordingly. With
14 respect to common equity, decisions about how and when profits are distributed to the
15 owners of the company are wholly within the purview of the owners themselves. They
16 may choose to pay dividends or they may choose not to pay dividends. Ratepayers
17 should not be held accountable for any acceleration or delay in the distribution of profits
18 that result from those decisions. Even though including the return on common equity
19 (through common dividends) in the calculations would tend to lower the cash working
20 capital allowance, I believe the Commission's policy of excluding common dividends
21 from the cash working capital calculations is the correct approach.²¹

²¹ If calculated properly, the inclusion of common dividends would decrease the CWC allowance. The Company has included the return component with zero days lag. This is wrong, since it suggests that the return is paid out

1 With respect to deferred tax expense, I recommend the Commission continue its
2 practice of excluding this item from the cash working capital calculations. Deferred tax
3 expense is a non-cash expense that already receives ratemaking treatment as an offset to
4 rate base.

5
6 **Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO**
7 **THE RATEMAKING TREATMENT FOR CASH WORKING CAPITAL?**

8 A: I recommend that depreciation expense, return on common equity and deferred taxes be
9 removed from OG&E's lead lag schedule. These items, often referred to as "non-cash"
10 items, are generally excluded from the cash working capital calculations. In Oklahoma,
11 the treatment of these items is well established. The inclusion of each of these items has
12 been litigated at the Commission, and the Commission has consistently found that they
13 should not be included in the lead lag study. Set forth below is an overview of the
14 treatment of non-cash items in lead lag studies in Oklahoma.

- 15 1. The Commission excluded common equity from the lead lag study in ONG's
16 1985 rate case, General Cause No. 29562.
- 17 2. The Commission excluded depreciation and deferred income tax expense (and
18 common equity as well) from the lead lag study in ONG's 1992 rate case, Cause
19 No. PUD 910001190.²²
- 20 3. The Commission excluded depreciation, common equity and deferred taxes from
21 the lead lag study in the OG&E's last rate case, Cause No. PUD 200500151.²³

immediately, which of course it is not. Dividends paid quarterly would equate to at least a 45 day lag, which is longer than the 38 day revenue lag. This means the inclusion of common dividends would decrease the CWC allowance. Nevertheless, the return on common equity should not be included in the calculation.

²² The parties specifically litigated the issue of including depreciation, common equity and deferred taxes in the 1992 ONG rate case. In its order, the Commission found that these items should not be included in the cash working capital calculations. (See pages 111 and 112 of the order and Section E, Schedule I attached to the order).

²³ At page 87 of Order No. 516261 in Cause No. 200500151, the Commission adopted staff's CWC recommendations. Staff's recommendations are outlined in the summary of Mr. Thompson's testimony included at

- 1 4. PSO does not include depreciation, common equity and deferred tax in its lead
2 lag studies.
- 3 5. ONG no longer includes depreciation, common equity and deferred taxes in its
4 filed lead lag studies.
- 5 6. To my knowledge, the Commission has consistently excluded depreciation,
6 common equity and deferred taxes from all lead lag calculations for
7 approximately the past twenty-five (25) years.²⁴

8 When the non-cash items of depreciation, common equity and deferred taxes are
9 removed from the lead-lag study, the Company's cash working capital requirement is
10 reduced by approximately \$38.3 million. This results in a negative cash working capital
11 requirement of approximately \$42.2 million.

12

13 **Q: HAVE YOU CORRECTED THE COMPANY'S LEAD-LAG STUDY TO**
14 **CONFORM TO THE COMMISSION'S DECISION IN THE PRIOR ONG**
15 **ORDER?**

16 A: Yes. The Company's treatment of non-cash items in its lead-lag study, which assigns a
17 zero day lag for depreciation, deferred income tax, ITC and common equity, causes the
18 overall cash working capital requirement to be greatly overstated. These items account
19 for approximately \$38.3 million of the Company's requested allowance. My calculation
20 of cash working capital utilizes the format that was adopted by this Commission in
21 Cause No. PUD 910001190 and reaffirmed in Cause No. PUD 200500151, which

page 81 of the order. Staff recommended that non-cash items such as depreciation, common equity, deferred taxes, and investment tax credits be excluded from the lead lag study. The exclusion of these items can be seen in the lead lag study attached to the order at Section E, Schedule I.

²⁴ OG&E had rate cases in 1991, 1996, 2001 and 2005. The 1996 and 2001 rate cases were settled. In the litigated cases, in 1991 the Company did not provide a lead lag study and the Commission gave the Company a zero cash

1 properly excludes common equity and non-cash items such as depreciation and deferred
2 tax expense from the lead-lag calculation.

3
4 **Q: HOW IS YOUR ADJUSTMENT CALCULATED?**

5 A: The corrections to the Company's lead-lag study are set forth in Schedule E-1 of the
6 OIEC Accounting Exhibit and the resulting adjustment is set forth below:

7
8 **Adjustment to Correct OG&E's Pro Forma CWC Allowance**

9 OG&E's Pro Forma Cash Working Capital Allowance (Schedule B-2) (\$ 4,427,690)

10 OIEC Recalculated Cash Working Capital Allowance (Sch. E-1) (\$43,441,083)

11 **OIEC Adjustment to the Cash Working Capital Allowance (\$39,013,393)**

working capital allowance as a result; in 2005, the Company's lead lag study included depreciation, common equity and deferred taxes, which the Commission removed.

II. F. REGULATORY ASSET – MCCLAIN PLANT

1 **Q: WHAT IS THE ISSUE REGARDING THE McCLAIN REGULATORY ASSET?**

2 A: In Section IV. G. of this testimony I explain that in the Company's last rate case, the
3 Commission authorized the Company to recover the McClain Plant Regulatory Asset
4 account balance over a four year period from January 1, 2006 through December 31,
5 2009.²⁵ I further explain that since the four year recovery period ends only four months
6 after new rates go into effect in this case,²⁶ the annual amortization of the McClain
7 balance of \$6,218,348 must be removed from pro forma operating expense or rates will
8 be set to recover this amount each year until the Company has another rate case,
9 resulting in a significant over-recovery of this account. Since the order in PUD 05-151
10 specifically states that the recovery will cease at the end of the four year period,²⁷ the
11 amortization must be adjusted in this case to comply with the previous order. In Section
12 IV. G., I adjust the annual amortization. In this section of testimony, I remove the
13 remaining asset balance from rate base. This adjustment is necessary so that the
14 Company will not earn a return on a balance that is fully amortized only four months
15 after new rates go into effect.

16
17 **Q: HOW IS THE ADJUSTMENT CALCULATED?**

18 A: The adjustment is set forth in the table below.

²⁵ The final order in Cause No. PUD 01-455 gave the Company the authority to defer, for the period of one year, the costs associated with owning and operating a new generation facility, including operating and maintenance costs, depreciation and a return on the investment. OG&E acquired the McClain plant in July of 2004 and deferred the costs of owning and operating the plant – for a 12-month period – in a regulatory asset account submitted for recovery in Cause No. PUD 05-00151.

III. OPERATING REVENUE ADJUSTMENTS

1 **Q: WHAT ISSUES HAVE YOU IDENTIFIED WITH RESPECT TO THE**
2 **COMPANY'S PRO FORMA REVENUE LEVELS?**

3 A: The only revenue adjustment I am proposing relates to the Company's Load Curtailment
4 Program for large customers. In the Company's Cost of Service Study, the interruptible
5 credits from this program are retained in the revenue streams of the Power and Light and
6 Large Power and Light classes. The resulting reduction in revenue for these classes in
7 effect places the entire burden of the program on these classes even though all classes
8 benefit from this program. Since the program clearly benefits all customers, the cost the
9 program should be recovered from all customer classes. In order to correct this
10 misallocation, I recommend removing the credits from the revenue streams of the Power
11 and Light and Large Power and Light classes and treating the interruptible credit
12 payments as an expense to be recovered through the fuel adjustment mechanism
13 allocated to the various classes through a production cost allocation. This means that the
14 revenue requirement needs to be increased by the amount of the credits that will be
15 recovered through the fuel clause. This adjustment will be discussed in more detail in
16 the cost of service testimony that will be filed on June 24th.

17
18 **OIEC Adjustment to Increase Revenues for Curtailment Credits \$2,681,200**

IV. OPERATING EXPENSE ISSUES

IV. A. PAYROLL ANNUALIZATION – (Six-Month Post Test Year Adjustment)

1 **Q: WHAT IS OG&E PROPOSING WITH RESPECT TO ITS PAYROLL COSTS?**

2 A: OG&E is proposing three payroll adjustments. The first adjustment annualizes payroll
3 expense at test year end and results in an increase of \$9,394,317. The second adjustment
4 annualizes the payroll costs for the Redbud plant employees added to OG&E's payroll
5 registers during the test year.²⁸ This adjustment results in an increase of \$2,611,793. A
6 third adjustment increases test year payroll cost for positions the Company would like to
7 fill after test year end. This adjustment results in an increase of \$6,840,938. The
8 Company also proposes related payroll tax increases associated with each adjustment.

9

10 **Q: DO YOU AGREE WITH THE COMPANY'S PROPOSED ADJUSTMENTS?**

11 A: No. There are problems with each of the Company's proposed adjustments. I address
12 each adjustment separately below.

13

14 **1. Payroll Expense Annualization – Six-Month Post Test Year Adjustment**

15

16 **Q: WHAT ARE THE PROBLEMS IDENTIFIED WITH THE FIRST**
17 **ADJUSTMENT?**

²⁸ All of the employees of the former owner of the plant who had been offered employment with OG&E were in place by November 21, 2008.

1 A: The first adjustment, which annualizes payroll costs at test year end, should be updated
2 to annualize payroll costs at the end of the statutory 6-month post test year period, March
3 31, 2009. This approach has been used by the Commission in the past because it
4 satisfies the 6-month rule and more closely aligns payroll levels with the updated plant
5 levels at the end of the 6-month post test year period. I believe the payroll levels at the
6 end of the 6-month period should be used for the payroll annualization if they represent a
7 genuine change in payroll costs.²⁹ Understandably, the Company did not have the
8 information available to make this adjustment when it filed its case. It has, however,
9 now re-calculated the annualization at March 31, 2009. The Company's re-calculated
10 annualization at March 31, 2009 should be used unless it can be shown that the March 31
11 payroll costs are not representative of the payroll levels that will exist during the rate-
12 effective period.

13

14 **2. Redbud Payroll Expense Adjustment**

15

16 **Q: WHAT ARE THE PROBLEMS WITH THE SECOND ADJUSTMENT?**

17 A: The second adjustment, which increases payroll costs for the added Redbud employees,
18 is improperly calculated. The Company's filed adjustment reflects 100% of the plant
19 employee costs rather than OG&E's 51% ownership share. OG&E has since re-
20 calculated the Redbud adjustment to reflect its 51% share of the costs. This re-calculated
21 Redbud adjustment should be used.

²⁹ If, on the other hand, payroll levels at the end of the 6-month period do not represent a real and ongoing change in payroll cost levels, they should not be used. In other words, if payroll costs at the end of the 6-month period

1

2

3. Unfilled Positions Adjustment

3

4

Q: WHAT ARE THE PROBLEMS WITH THE THIRD ADJUSTMENT?

5

A: The third adjustment, which increases payroll costs for vacant positions the Company hoped to fill after test year end, should be eliminated. This adjustment becomes unnecessary when payroll cost levels are updated to the 6-month post test year cut off. Any positions actually filled by the end of the 6-month period would be captured in the March 31, 2009 annualization, making this adjustment superfluous.

6

7

8

9

10

11

Q: WHAT PAYROLL ADJUSTMENTS ARE YOU PROPOSING?

12

A: My recommended payroll adjustments (1) update the payroll annualization to March 31, 2009, six months after test year end, (2) correct the Redbud payroll adjustment to reflect OG&E's 51% ownership interest in the plant, and (3) eliminate the Company's *unfilled positions* adjustment. The impact of these adjustments is set forth in the table below.

13

14

15

OIEC Proposed Payroll Adjustments				
Adj.	Description	OG&E Adj.	Corrected Amt	OIEC Adj.
1	Payroll Annualization	\$9,394,317 ³⁰	\$11,280,430	\$1,886,113
2	Redbud Payroll	\$2,611,793 ³¹	\$ 1,314,515	(\$1,297,278)
3	Unfilled Positions	\$6,370,182 ³²	\$ 0.00	(\$6,370,182)

were only temporarily high, or artificially high for some reason, they should not be used.

³⁰ W/P H-2-18.

³¹ A/P H-2-27.

³² W/P H-2-29.

1 **Q: WHY DID YOU CHOOSE TO ANNUALIZE PAYROLL AT MARCH 31, 2009?**

2 A: In Oklahoma, to the extent possible, we give effect to known and measurable changes
3 that occur within the six month period following test year end. Like the adjustments to
4 Plant, Accumulated Depreciation, Deferred Taxes, Inventories, Customers Deposits and
5 Operating Revenues, I adjusted payroll expense to reflect the Company's actual payroll
6 expense at March 31, 2009.

7

8 **Q: WHAT OTHER PAYROLL COST ADJUSTMENTS ARE YOU PROPOSING?**

9 A: I am proposing to recognize the corresponding payroll tax adjustments associated with
10 payroll adjustments above. The related payroll tax adjustments are set forth in the table
11 below:

OIEC Proposed Payroll Tax Adjustments				
Adj.	Description	OG&E Adj.	Corrected Amt	OIEC Adj.
1	Payroll Annualization	\$694,240 ³³	\$866,337	\$172,097
2	Redbud Payroll	\$193,012 ³⁴	\$97,142	(\$ 95,869)
3	Unfilled Positions	\$470,756 ³⁵	\$ 0.00	(\$470,745)

³³ W/P H-2-18.1.

³⁴ W/P H-2-27.

³⁵ W/P H-2-29.

IV. B ANNUAL INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

1 **Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF OG&E'S INCENTIVE**
2 **COMPENSATION PLANS.**

3 A. OG&E provides an annual cash incentive compensation plan to all employees called the
4 *Teamshare* plan. The Company also provides a long-term stock incentive plan to
5 officers and key employees of the Company.
6

7 **Q. WHAT ADJUSTMENT ARE YOU PROPOSING WITH RESPECT TO THE**
8 **COMPANY'S ANNUAL TEAMSHARE INCENTIVE PLAN?**

9 A. I am proposing to exclude 50% of the annual incentive plan expense. This
10 recommended sharing of *Teamshare* costs between the Company and its customers
11 reflects the fact that the main purpose of the *Teamshare* payments is to increase the
12 financial performance of the Company. As a general rule, regulatory commissions
13 exclude incentive compensation associated with financial performance.³⁶
14

³⁶ See ALJ's Proposal for Decision in PUC Docket No. 28840, Footnote 284, in reference to the CCR Initial Brief at 25 where the following list of cases showing that incentives are disallowed in many states as a matter of policy is found. See, *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). Also, see the results of the Incentive Survey conducted by the Garrett Group provided in this testimony.

1 Q. WHAT IS THE GENERAL RATIONALE FOR EXCLUDING INCENTIVE
2 COMPENSATION TIED TO FINANCIAL PERFORMANCE?

3 A. When incentive compensation costs associated with financial performance are excluded
4 from rates, the rationale is generally based on one or more of the following reasons:

5 (1) **Payment is uncertain.** Often, payment of incentive compensation is conditioned
6 upon meeting some predetermined financial goal such as achieving a certain
7 increase in earnings, reaching a targeted stock price or meeting budget objectives.
8 If the predetermined goals are not met, the incentive payment is not made, or
9 payment is made at some lesser amount. Therefore, there is no certainty from
10 year to year what the level of the payment may be or whether the payment will be
11 made at all. It is generally considered inappropriate to set rates to recover a
12 tentative level of expense.

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

30 (3) **Earnings-based incentive plans can discourage conservation.** When incentive
31 payments are based on earnings, employees may not be as supportive of
32 conservation programs designed to reduce usage if they perceive these programs
33 could adversely impact incentive payment levels. To the extent earnings-based
34 incentive plans discourage conservation and demand-side management programs,
35 these plans would not be in the public interest. This point is especially important
36 in light of the growing focus on energy efficiency at both the national and state
37 level.

1 **(4) The utility and its stockholders assume none of the financial risks associated**
2 **with incentive payments.** Ratepayers assume the risk that the amounts collected
3 through rates for incentive payments will instead be retained by the utility
4 whenever targeted increases are not reached. Employees assume the risk that the
5 incentive payments will not be made in a given year. However, the utility and its
6 stockholders assume no risk associated with these payments. Instead, the
7 company's only responsibility is to decide who gets the money, the stockholders
8 or the employees.

9 **(5) Incentive payments based on financial performance measures should be**
10 **made out of increased earnings.** Whatever the targets or goals may be that
11 trigger an incentive payment, when the plan is based in whole or in part on
12 financial performance measures there is always a financial benefit to the
13 company that comes from achieving these objectives. This financial benefit
14 should provide ample funds from which to make the payment. If not, the
15 incentive plan was poorly conceived in the first place. As such, employees
16 should be compensated out of the increased earnings, and not through rates.

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

29 Even though regulators often exclude incentive compensation payments based on one or
30 more of the reasons outlined above, this does not mean that regulated companies should
31 not offer incentive compensation packages. To the contrary, incentive plans that
32 motivate employees to achieve increased efficiencies should be encouraged. However,
33 since the utility retains the savings generated from these increased efficiencies between
34 rate cases, payment to the employees for these plans should be made from a portion of

1 the savings these plans help achieve. Thus, incentive compensation plans designed to
2 enhance financial performance need not be subsidized by ratepayers.

3
4 **Q. HOW IS INCENTIVE COMPENSATION TREATED IN OTHER STATES?**

5 A. The results of the Incentive Survey of the Western States taken by the Garrett Group in
6 2007 and updated in 2009 show that most states follow the general rule that incentive
7 payments designed to increase the financial position of the utility are excluded from
8 rates. Some states disallow incentive pay using other criteria. None of the jurisdictions
9 surveyed allow full recovery of incentive compensation through rates as a general rule.

10 The results of the survey are set forth below.

States that closely follow the Financial Performance rule

11 **Washington:** Incentive plans are evaluated on a case by case basis. The portions of the
12 plan tied to measures such as reliability and customer satisfaction are
13 allowed and the portions tied to financial measures and the bottom line
14 are disallowed.³⁷

15 **Oregon:** The commission's general policy is to evaluate plans based on whether
16 they benefit the customers or the company. Customer-based plans
17 involving reliability, response speed, etc. are called "merit" plans.
18 Company-based plans which track increases to the bottom line, ROE, etc.
19 are called "performance" plans. 50% of the cost of merit plans is
20 disallowed and 75% of the performance plans is disallowed. 100% of
21 officer bonuses are disallowed.³⁸

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

³⁷ See the Order in Pacific Power and Light Docket 061546.

³⁸ A recent order reflecting this policy can be found in Docket UE 197, Order No. 09-020.

1 plans would be funded in rates and that 100% of the executive long-term
2 stock plans would be disallowed.³⁹

3 **Idaho:** The commission's basic policy for evaluating incentive compensation
4 plans involves determining who benefits, the customer or the company.
5 This treatment has been refined in the recent Idaho Power rate case for
6 plans which benefit the customer but require a financial trigger to be paid.
7 For these plans the commission reduced the percentage allowed in rates.
8 The commission also now does not include any executive compensation
9 in rates.⁴⁰

10 **Utah:** The commission's general policy is to allow in rates the parts of a plan
11 that are tied to ratepayer benefits and disallow the parts tied to financial
12 goals. Executive incentive compensation is excluded from rates.⁴¹

13 **S. Dakota.** The commission's general policy is to disallow the portion of incentive
14 plans that are based on returns. Current treatment also includes
15 disallowing both executive and non-executive management incentive
16 compensation. There are no incentive compensation plans for union
17 employees.

18 **Oklahoma:** The commission excludes incentive payments tied to financial
19 performance. From a practical perspective this means that all executive
20 stock plans are excluded and some portion of the annual cash plan for all
21 employees. Since the commission has not been able to determine in
22 recent cases the precise portion of the annual plans tied to financial
23 measures, the commission has excluded 50% of the annual plans. 100%
24 of the executive stock plans are excluded.⁴²

25 **Texas:** The general rule is that incentive payments designed to increase the
26 financial position of the utility are excluded. For example, in PUC
27 Docket No. 28840,⁴³ the commission disallowed sixty-six percent (66%)
28 of AEP-Texas Central's test year incentive payments in the amount of

³⁹ Southern California Edison (Application #: 07-11-011, Decision #: 09-03-025)

⁴⁰ 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.

⁴¹ The recent final order in 07-35-93 follows this general policy. See also US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01, pp. 10-12.

⁴² See e.g., AEP-PSO Cause No. PUD 06-285; OG&E Cause No. PUD 05-151; and ONG Cause No. PUD 04-610.

⁴³ *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).

1 \$4.2 million. This was the portion of the utility’s incentive payments that
2 were based on financial performance measures.⁴⁴

3 **New Mexico:** The commission does not favor incentive compensation plans that are tied
4 to financial goals and tends to allow in rates those based on operational
5 goals. This standard is applied to all levels of utility employees and tends
6 to eliminate the greater portion of executive plans.⁴⁵

7 **Colorado:** Colorado has no rules or statutes and due to black-box settlements has no
8 recent orders on point. Historically, the policy of the consumer
9 advocate’s office has been to disallow plans tied to price per share and
10 allow those plans tied to quality of service and benefits for ratepayers. In
11 the current Public Service Company of Colorado case, Staff has argued to
12 exclude all incentive compensation from rates because the payments are
13 discretionary and the incentive compensation benefits only the
14 shareholder and should be paid by shareholders. The goals related to
15 ratepayer benefits are part of the job and compensated through regular
16 wage and salary.

17 **Missouri:** Value to customers is the policy. The plan goals must benefit customers
18 or the plan is not included in rates. Plans based on rate of return, for
19 example, are not allowed. The same criteria are used for executive plans
20 and few are allowed.⁴⁶

21 **Arkansas:** Arkansas recently changed its incentive policy. In the past, the
22 commission allowed 100% of the portion based on operation goals and
23 50% of the portion that included financial goals. Under the new policy,
24 Arkansas excludes 100% of the executive plans. 50% of the portion of
25 any plan for regular employees that benefits both the company and the
26 customers is allowed.⁴⁷

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.

⁴⁴ 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.

⁴⁵ See Docket 07-00077-UT.

⁴⁶ See recent Kansas City Power and Light and Empire Electric District orders on the commission’s website.

⁴⁷ Entergy Arkansas, 06-101-U, Order No. 10.

1 interests. The portions of these plans that are allowed into rates are
2 tracked and must be returned to ratepayers if they are not paid to
3 employees. Executive plans are largely not allowed.⁴⁹

4 **Q. WHY IS THE DISTINCTION BETWEEN FINANCIAL PERFORMANCE**
5 **MEASURES AND OPERATIONAL MEASURES AN IMPORTANT**
6 **DISTINCTION FOR INCENTIVE COMPENSATION ANALYSIS?**

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

18
19 **Q: ARE OG&E’s INCENTIVE PAYMENTS BASED ON FINANCIAL**
20 **PERFORMANCE MEASURES?**

⁴⁹ See General Rate Case E002/GR/05/1428, September 1, 2006.

1 A: Yes they are. A review of the Company's incentive plan, called Teamshare, indicates
2 that the Company Performance Goals will be based on one or more of the following:

3 Total shareholder return, return on equity, return on capital, earnings per
4 share, market share, stock price, sales, costs, net operating income, net
5 income, return of assets, earnings before income taxes, depreciation and
6 amortization, return on total assets employed, capital expenditures,
7 earnings before income taxes, economic value added, cash flow, retained
8 earnings, results of customer satisfaction surveys, aggregate product price
9 and other product price measures, safety record, service reliability,
10 demand side management (including conservation and load management),
11 operating and/or maintenance cost management (including operation and
12 maintenance expense per kWh), and energy production availability
13 performance measures and such other measures or goals as may be
14 determined by the Committee.

15 Clearly, most of the states goals are financial performance goals, in effect, goals
16 intended to promote and enhance the financial condition of the company. However, a
17 few of the stated goals are customer-related goals intended to increase customer
18 satisfaction and reliability. These customer-related goals include (1) results of customer
19 satisfaction surveys, (2) service reliability, (3) aggregate product price and (4) demand
20 side management goals.

21

22 **Q: WHAT ARE YOU RECOMMENDING WITH RESPECT TO THE COMPANY'S**
23 **TEAMSHARE INCENTIVE EXPENSE?**

24 A: I am recommending a 50/50 sharing of these costs between shareholders and ratepayers.
25 This recommendation is based on the recognition that not all of the company goals are
26 financial performance goals. Some of the goals are instead designed to increase

1 customer satisfaction and reliability. Because ratepayers receive at least some benefit
2 from these customer-related goals, some portion of the plan costs should be allowed.

3
4 **Q: HAS THIS COMMISSION ADDRESSED INCENTIVE COMPENSATION**
5 **PAYMENTS TO NON-EXECUTIVE EMPLOYEES IN PAST ORDERS?**

6 A: Yes. In its order in PUD 91-1190, at page 145, this Commission addressed ONG's
7 Gainshare Plan and the Executive Stock Performance Plan and disallowed the entire cost
8 of both plans, finding that the incentive plans were designed to increase corporate
9 earnings. Recently, in PUD 04-610, the ALJ recommended disallowance of the entire
10 costs of ONG's executive and non-executive incentive compensation payments. With
11 respect to non-executive incentive compensation the ALJ made the following
12 recommendation:

13 The ALJ finds that incentive compensation should be disallowed
14 from inclusion in the rates paid by Oklahoma Natural's ratepayers.
15 Incentive compensation is typically tied to the attainment of
16 certain financial goals, efficiencies in operations or similar
17 criteria, which create additional income to the company, cost
18 savings or other financial benefit. The ALJ concurs with the
19 argument of the Staff and AG that a well designed incentive
20 compensation plan will generate resources from which to pay the
21 incentives to the employees. Therefore, the ALJ recommends
22 adoption of the Staff's recommended disallowance in the amount
23 of \$2,671,985.
24

25 In OG&E's last rate case, the Commission's final order disallowed 60% of the
26 Teamshare expense.

27 **Incentive Compensation.** OG&E presents \$9,308,619 in expense
28 for incentive compensation under the "TeamShare" plan. The

1 Referee does not accept the full amount as proposed by the
2 company but reduces the expense by \$5,582,192.
3

4 **Q: WHAT IS THE AMOUNT OF YOUR PROPOSED ADJUSTMENT?**

5 A: OG&E's response to Attorney General's Data Request 6-25 indicates that the total
6 amount of Teamshare costs in pro forma operating expense is \$13,824,239. I am
7 recommending that 50% of this amount be excluded from pro forma operating expense.
8

9 **Q: HOW IS THE OIEC ADJUSTMENT CALCULATED?**

10 A: OIEC's adjustment to operating expense for regular incentives is set forth below.

11	Annual Incentive Plan Payments in Pro Forma Expense	\$13,194,244
12	Percentage Associated with Company Financial Goals	<u>50 %</u>
13	OIEC Adjustment to Annual Incentive Plans	<u>\$ 6,597,122</u>

IV. C. LONG-TERM EXECUTIVE STOCK INCENTIVE ADJUSTMENT

1 **Q: WHAT HAS THE COMPANY INCLUDED IN RATES FOR LONG-TERM**
2 **INCENTIVE PLANS FOR EXECUTIVES AND KEY EMPLOYEES OF THE**
3 **COMPANY?**

4 A: The Company is proposing to recover \$3,155,101 for its long-term executive stock
5 plan.⁵⁰

6
7 **Q: WHAT TYPES OF INCENTIVES ARE PROVIDED TO EXECUTIVES AT**
8 **OG&E?**

9 A: The Company provides a stock incentive plan to the officers of the Company and certain
10 employees. Officers and employees who are “responsible for or contribute to the
11 management, growth and profitability of the Company” are eligible for awards under the
12 plan.

13
14 **Q: DO YOU RECOMMEND THE INCLUSION OF EXECUTIVE STOCK**
15 **INCENTIVE EXPENSE IN RATES?**

16 A: No. Incentive compensation payments to officers, executives and key employees of a
17 utility company are generally excluded for ratemaking purposes, and I agree with this
18 treatment. Executive stock-based compensation in particular is excluded in most
19 jurisdictions because stock-based compensation is, on its face, tied to financial
20 performance. Since officers of any corporation have a duty of loyalty to the corporation

1 itself and not to the customers of the company, these individuals typically put the
2 interests of the company first. Undoubtedly, the interests of the company and the
3 interests of the customer are not always the same, and at times, can be quite divergent.
4 This natural divergence of interests creates a situation where not every cost associated
5 with executive compensation is presumed to be a necessary cost of providing utility
6 service. Many regulators are inclined to exclude executive bonuses, incentive
7 compensation and supplemental benefits from utility rates, understanding that these costs
8 would be better borne by the utility shareholders.

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

⁵⁰ According to OG&E's response to OIEC Data Request 3-6.

1 **Q: HOW IS EXECUTIVE INCENTIVE COMPENSATION TREATED IN OTHER**
2 **STATES?**

3 A: In April of 2007, the Garrett Group, LLC conducted a survey of utility commissions in
4 the western United States regarding the rate treatment of incentive compensation. The
5 survey results were updated in early 2009. The results of this survey show that most
6 states follow guidelines similar to those described above for Texas, Oklahoma and Utah,
7 where incentive pay associated with financial performance is not allowed. This means
8 that executive incentives are not allowed in most states. A synopsis of the survey results
9 from each state is included in the next section of this testimony, and the treatment of
10 executive incentives in each state is underlined. According to the survey, the following
11 states exclude all or virtually all executive incentive pay: Oregon, California, Idaho,
12 Utah, South Dakota, Oklahoma, Wyoming, North Dakota, Missouri, Arkansas,
13 Louisiana, Minnesota and Nevada. Other states, like Washington and Texas, simply
14 apply the *financial performance* rule, which has the affect of excluding executive
15 incentives.

16
17 **Q: WHEN UTILITIES DO SEEK TO INCLUDE EXECUTIVE STOCK**
18 **COMPENSATION IN RATES, WHAT RATIONALE IS GENERALLY**
19 **PROVIDED?**

20 A: Generally, utilities argue that executive incentives are part of an overall compensation
21 package that is designed to attract and retain qualified personnel.

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

2 A: No. When utilities, such as OG&E, compete with other utilities for qualified executives,
3 and the executive incentive compensation of the other utilities is not being recovered
4 through rates, OG&E is not put at a disadvantage when its executive incentive
5 compensation is excluded as well.

6

7 **Q: ARE OG&E'S INCENTIVE PAYMENTS BASED ON FINANCIAL**
8 **PERFORMANCE MEASURES?**

9 A: Yes they are. A review of the Company's incentive plan indicates that the executive
10 incentive plan is based almost solely on financial performance measures.

11

12 **Q: HAS THIS COMMISSION ADDRESSED EXECUTIVE INCENTIVE**
13 **COMPENSATION PLANS IN PAST ORDERS?**

14 A: Yes. On two separate occasions this Commission has decided the issue of whether to
15 include incentive compensation in rates. On both occasions the Commission excluded
16 the entire amount of incentive payments made during the test year. In its order in Cause
17 No. PUD 91-1190, at page 145, this Commission addressed ONG's employee incentive
18 plans, the Gainshare Plan and the Executive Stock Performance Plan. The Commission
19 disallowed the entire cost of both plans, which at that time was \$2,025,857, based upon
20 the arguments of Staff and the Attorney General that the plans were designed to increase
21 corporate earnings. More recently, in Cause No. PUD 04-610, after a hearing on the
22 merits, the ALJ's recommendations disallowed the entire cost of both the executive and

1 non-executive payments. With respect to the executive incentive compensation the
2 ALJ's recommendation states:

3 The ALJ finds that Executive Compensation typically includes a
4 component that is based upon certain goals of the company being
5 achieved. As with the incentive compensation addressed above,
6 the ALJ finds that an appropriately designed executive incentive
7 compensation will generate revenues or cost savings equivalent to
8 the compensation paid. Therefore, the ALJ finds that incentive
9 compensation provides a benefit to the shareholders rather than to
10 the ratepayers. It is therefore the recommendation of the ALJ that
11 the Executive Compensation incentives adjustment proposed by
12 Staff be adopted.

13 In PSO's 2006 rate case, the Commission disallowed 100% of the utility's long-term
14 incentive plan.

15 s. Long-Term Executive Stock Incentive Plan. The Commission
16 adopts Staff and OIEC's proposal to remove \$1,268,591 from PSO's cost-
17 of-service. This amount is reflected on HE-17 at page 16 of 24, OIEC
18 Adjustment No. H-5. The Commission finds that the FICA tax expense
19 associated with the long term executive stock incentive payments should
20 be removed for ratemaking purposes in the amount of \$225,567, as
21 proposed by OIEC. PSO's long-term executive incentive plan is
22 specifically designed to tie executive compensation to the financial
23 performance of AEP. It would be inappropriate to require ratepayers to
24 bear the costs of incentive plans designed to encourage employees to put
25 the interest of the shareholders first. Further, a well designed incentive
26 plan should pay for itself. Thus, there is no need to include in rates
27 amounts that will be provided through higher earnings.⁵¹

28 In PSO's most recent rate case decided earlier this year, the Commission again
29 disallowed 100% of the utility's long-term incentive costs.

30 With regard to long term incentive compensation, the Commission finds
31 that the recommendation of the AG, OIEC and Staff to disallow 100% of
32 long term incentive compensation is reasonable and should be adopted by
33 the Commission. The performance measures that result in the payment of

51 See Final Order in Cause No. PUD 200600285 at page 145.

1 long term incentive compensation are financial goals that benefit
2 shareholders, rather than ratepayers.⁵²

3 **Q: HOW IS LONG-TERM EXECUTIVE INCENTIVE COMPENSATION**
4 **TREATED IN THE OTHER STATES WHERE YOU REGULARLY PRACTICE?**

5 A: In Nevada Power's pending rate case, the Hearing Officer recommended excluding from
6 rates 100% of the long-term plan costs for executives and key employees of the
7 company, based on the fact that these costs mainly benefit shareholders.⁵³ In Utah, all
8 long-term incentive plans for executives are excluded. In Utah, PacifiCorp no longer
9 includes the cost of its long-term executive incentive plan in its rate case filings.

10
11 **Q: WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE**
12 **COMPANY'S STOCK INCENTIVE COMPENSATION?**

13 A: For the reasons outlined above and based upon prior Commission orders, I am
14 recommending that 100% of the Company's stock incentive expense be excluded for
15 ratemaking purposes.

16
17 **OIEC Adjustment to Exclude 100% of the Stock Incentive Plan \$3,155,101**

⁵² Order No. 564437 in Cause No. PUD 200800144 at page 21.

⁵³ See Draft Order issued June 17, 2009 in Docket No. 08-12002, at page 138

IV. D. SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ADJUSTMENT

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

2 A: The Company provides supplemental retirement benefits to officers, and division presidents
3 of the Company. Supplemental retirement plans for highly compensated individuals are
4 provided because benefits under the general pension plans are subject to certain limitations
5 under the Internal Revenue Code. Benefits payable under these supplemental plans are
6 typically equivalent to the amounts that would have been paid but for the limitations
7 imposed by the Code. In general, the limitations imposed by the Code allow for the
8 computation of benefits on annual compensation levels of up to \$225,000 for the year.⁵⁴
9 Retirement benefits on compensation levels in excess of the \$225,000 limitation are paid
10 through supplemental plans. Supplemental retirement plans for highly compensated
11 employees are designed to provide benefits in addition to the benefits provided under the
12 general pension plans of the company.

13

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

16 A: The amount of Supplemental Executive Retirement Plan costs included in OG&E's filed
17 cost-of-service was \$698,642.⁵⁵

18

19 **Q: DO YOU RECOMMEND A SHARING OF THE TOTAL EXECUTIVE**
20 **RETIREMENT BENEFIT COSTS?**

⁵⁴ The limits are \$225,000 for 2007, \$230,000 for 2008 and \$245,000 for 2009.

1 A: Yes. I recommend that shareholders pay for the costs of the supplemental executive
2 retirement plans. This means that ratepayers pay for all of the executive benefits
3 included in the Company's regular pension plans, and that shareholders pay for the
4 additional executive benefits included in the supplemental plan. For ratemaking
5 purposes, shareholders should bear the additional costs associated with supplemental
6 benefits to highly compensated executives, since these costs are not necessary for the
7 provision of utility service, but are instead discretionary costs of the shareholders
8 designed to attract, retain and reward highly compensated employees. However, because
9 officers of any corporation have a duty of loyalty to the corporation, these individuals
10 will put the interest of the company first. This creates a situation where not every cost
11 associated with executive compensation is presumed to be a cost appropriately passed on
12 to ratepayers. Many regulators are inclined to exclude executive bonuses, incentive
13 compensation and supplemental benefits from utility rates, understanding that these costs
14 would be better borne by the utility shareholders.⁵⁶ This adjustment is set forth below.

15

16 **OIEC Adjustment to Remove SERP Expense** **\$698,642**

55 See WP H-2-3.

56 For example, this Commission excluded SERP costs in PSO's last rate case, PUD 200600285.

IV. E. AD VALOREM TAX EXPENSE ADJUSTMENT

1 **Q: WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS AD**
2 **VALOREM TAX EXPENSE?**

3 A: The Company proposes an increase to test year ad valorem tax expense based on an
4 estimated assessment of its pro forma plant levels. Through its proposed adjustment,
5 OG&E seeks to increase ad valorem tax expense by \$3,791,820. OG&E's original
6 adjustment was based on an estimate of the State's valuation of OG&E's tax base. After
7 this case was filed, however, OG&E arrived at an actual agreed upon valuation with the
8 tax commission. By applying the current millages to the agreed upon valuation, OG&E
9 was able to calculate a reasonable estimate of its ad valorem tax liability going forward
10 based on assets in place during the 6-month post test year period. This calculation
11 results in an additional \$1,711,988 adjustment to ad valorem tax expense.

12

13 **Q: WHAT INCREASE DO YOU RECOMMEND?**

14 A: I recommend the Commission accept the Company's calculation of ad valorem tax
15 liability based upon the agreed upon valuation.

16

17 **OIEC Ad Valorem Tax Expense Adjustment (Increase) \$ 1,711,988**

IV. F. REGULATORY ASSET AMORTIZATION – DEFERRED PENSION EXPENSE

1 **Q: WHAT IS THE ISSUE REGARDING THE PENSION ASSET AMORTIZATION?**

2 A: As explained in previous sections of this testimony, the Commission authorized the
3 Company in its last rate case to track the over and under recovery of its annual pension
4 expense in a regulatory asset/liability account. Specifically, that Order stated:

5 w. **Tracking Mechanism for Pension Expense.** The Referee adopts Staff's
6 proposal and authorizes OG&E to set up regulatory asset and liability
7 accounts to track the changes in pension expense. However, as
8 recommended by Staff, the Commission will decide what level will be
9 allowed or disallowed in future rate cases on a case-by-case basis.

10 From the last rate case through the end of the test year, the Company's actual pension
11 expense exceeded the amount included in rates and the Company accumulated the
12 difference in a Deferred Pension Expense account. The Company now seeks to recover
13 the accumulated balance through rates. Specifically, the Company's adjustment increase
14 pro forma operating expense by \$9,653,550 to reflect a 2-year amortization of the
15 projected account balance through August 31, 2009 of \$19,307,100. The Company
16 chose August 31, 2009, even though it is beyond the 6-month cut-off, because August is
17 the last month before the new rates from this case go into effect.

18

19 **Q: DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT AS PROPOSED?**

20 A: No, not entirely. The correct amount for recovery, if the August 31, 2009 is to be used,
21 would be the projected balance using the latest actuarial report.⁵⁷ According to the latest

⁵⁷ The Company would agree with this treatment but, understandably, the Company did not have this information available when it filed its case.

1 report, the balance in the account at end of August should be \$17,438,324. Also, the
 2 Company is seeking a 2-year recovery period, but I would recommend a four-year
 3 recovery instead. Given the large rate increase requested by the Company coupled with
 4 the financial uncertainty of the recession, I believe the Commission should look for
 5 adjustments that will mitigate the rate increase without harming the Company. This
 6 adjustment accomplishes these goals. By spreading the recovery over a longer period,
 7 rates are kept lower now and the Company suffers no financial harm, since the amount
 8 recovered in rates matches the amount amortized to expense each year under either
 9 approach.

11 **Q: WHAT IS THE AMOUNT OF YOUR PROPOSED ADJUSTMENT?**

12 A: My adjustment compares a 4-year amortization of \$17,438,324, or \$4,359,581, with the
 13 \$9,394,317 amortization proposed by OG&E. This comparison results in an adjustment
 14 of \$5,293,969 as set forth in the table below.

OIEC Pension Regulatory Asset Adjustment				
Ln	Description	Balance	Amo. Period	Amount
1	OG&E Amortization	\$19,307,100	2 Years	\$9,394,317
2	OIEC Amortization	\$17,438,324	4 Years	\$4,359,581
3	OIEC Adjustment			(\$5,293,969)

15 **Q: DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO GO BEYOND THE**
 16 **6-MONTH CUT OFF DATE?**

1 A: I do not agree with Mr. Rowlett's testimony at page 7, lines 12-18, where he states that
2 the Commission has *broad discretion* to approve changes beyond the 6-month cut off. I
3 believe the Commission's discretion is limited by Title 17 § 284. However, here the
4 adjustment deals with a *regulatory asset account established by the Commission*. With a
5 regulatory asset or liability account, it sometimes becomes necessary to look beyond the
6 cut off date to fully satisfy the purpose of the special treatment ordered by the
7 Commission. That is the case here. In the prior order, the Commission allowed the
8 Company to defer – during the rate effective period – the difference between actual
9 pension expense incurred and the level used to establish rates. The rate effective period
10 for the last rate case ends when new rates from this case go into effect, sometime around
11 August 31, 2009. By using the projected account balance through August 31, 2009, the
12 Company will receive the full benefit of the regulatory asset treatment ordered by the
13 Commission in the prior case.

IV. G. REGULATORY ASSET AMORTIZATION – McCLAIN PLANT

1 **Q: WHAT IS THE ISSUE REGARDING THE McCLAIN REGULATORY ASSET**
2 **AMORTIZATION?**

3 A: In the Company's last rate case, the Commission authorized the Company to recover the
4 McClain Plant Regulatory Asset account balance over a four year period from January 1,
5 2006 through December 31, 2009.⁵⁸ The authorized balance in the account was
6 \$24,873,394.⁵⁹ The authorized annual amortization was \$6,218,348.⁶⁰ Since the four
7 year recovery period ends only four months after new rates go into effect in this case,⁶¹
8 the annual amortization of \$6,218,348 must be removed from pro forma operating
9 expense or rates will be set to recover this amount each year until the Company has
10 another rate case, resulting in a significant over-recovery of this account. Since the order
11 in PUD 05-151 specifically states that the recovery will cease at the end of the four year
12 period,⁶² the amortization must be adjusted in this case to comply with the previous
13 order.

14
15 **Q: HOW IS THE ADJUSTMENT CALCULATED?**

16 A: The adjustment is set forth in the table below.

⁵⁸ The final order in Cause No. PUD 01-455 gave the Company the authority to defer, for the period of one year, the costs associated with owning and operating a new generation facility, including operating and maintenance costs, depreciation and a return on the investment. OG&E acquired the McClain plant in July of 2004 and deferred the costs of owning and operating the plant – for a 12-month period – in a regulatory asset account submitted for recovery in Cause No. PUD 05-00151.

⁵⁹ See Section C.9. of the final order in Cause No. PUD 05-151.

⁶⁰ $\$24,873,394 / 4 = \$6,218,348$.

⁶¹ The amortization ends December 2009; new rates go into effect September 2009.

⁶² See Section C.9.a.(1) of the final order in Cause No. PUD 05-151.

OIEC Adjustment to Remove McClain Asset Amortization	
Remove McClain Regulatory Asset Annual Amortization	(\$6,218,348)
Add Back Last 4-months of Recovery Spread over a 2-year Rate Period	\$1,036,391
OIEC Adjustment to Remove McClain Regulatory Asset Amortization	(\$5,181,957)

1 This adjustment provides a full recovery of the unamortized balance still on the books
2 when new rate go into effect and results in a \$5,181,957 reduction in pro forma operating
3 expense.

4

5 **Q: THIS ADJUSTMENT ALSO GOES BEYOND THE 6-MONTH POST TEST**
6 **YEAR CUT OFF. WHY IS IT ACCEPTABLE TO LOOK BEYOND THE CUT**
7 **OFF IN THIS SITUATION?**

8 A: In this situation we are dealing with a regulatory asset account established by the
9 Commission. To give full effect to the treatment ordered by the Commission it becomes
10 necessary to look beyond the normal cut-off period. In such situations, where a prior
11 order supersedes the general rule regarding the 6-month cut-off, it is necessary to look
12 beyond the cut-off date to comply with such prior Commission order.

V. **DEPRECIATION EXPENSE ADJUSTMENT**

1 **Q: WHAT IS THE ISSUE WITH DEPRECIATION?**

2 A: The Company's depreciation expense level needs to be increased to recognize plant
3 balances at March 31, 2009, using the Company's approved depreciation rates. This
4 adjustment is necessary to synchronize the major cost centers of the Company, including
5 plant, accumulated depreciation, deferred income tax, inventories, payroll, ad valorem
6 tax and depreciation at the 6-month post test year cut off date, March 31, 2009.⁶³ The
7 adjustment is set forth below and is reflected in the OIEC Accounting Exhibit at
8 Schedule H-3.

9

10 **Adjustment to Apply OG&E's Proposed Rates to Plant at 3-31-09 (\$ 264,012)⁶⁴**

63 Revenue levels should also be updated. However, our review of revenues at March 31, 2009 did not reveal a material change in the revenue levels.

64 The adjustment to update depreciation to 3/31/09 increases PSO's requested depreciation expense.

VI. ADJUSTMENTS PROPOSED BY OTHER OIEC WITNESSES

1 **Q: PLEASE PROVIDE A LIST OF THE ADJUSTMENTS SPONSORED BY THE**
2 **OTHER OIEC WITNESSES.**

3 **A:** The recommendations of the other OIEC witnesses are set forth below:
4

5	<u>Recommendations of Mr. David Parcell</u>	<u>Cost</u>	<u>Capital Ratio</u>
6	Return on Common Equity	10.000%	54.142%
7	Cost of Long-Term Debt	5.414%	45.858%

VII. CONCLUSION

1 **Q: WHAT IS THE OVERALL IMPACT OF OIEC'S RECOMMENDATIONS ON**
2 **THE COMPANY'S PROPOSED REVENUE REQUIREMENTS?**

3 A: The overall impact of the OIEC adjustments on OG&E's requested revenue requirement
4 on a total company basis are set forth below:

5	Rate Increase Proposed by OG&E	\$110,325,330
6	OIEC Adjustments	<u>\$ 97,741,603</u> ⁶⁵
7	Rate Increase Proposed by OIEC	<u>\$ 12,583,727</u>

8
9 **Q: DO YOU HAVE ANY FURTHER COMMENTS?**

10 A: Yes. My recommendations do not address every potential issue affecting OG&E's
11 revenue requirement. I addressed many of what I considered to be material issues in this
12 case. The fact that I do not express an opinion on a particular issue is not to be
13 interpreted as agreement with the Company's position on that issue.

14
15 **Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?**

16 A: Yes, it does.

⁶⁵ These recommended adjustments do not reflect OIEC's rate design recommendations which will result in a further reduction to the rate increase attributable to the industrial customer classes.

QUALIFICATIONS OF MARK E. GARRETT

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. **Nevada Power Company, 2009, (Docket No. 08-12002)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”)¹ 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.
2. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031)** – Participating as an expert witness on behalf of the Oklahoma Industrial Energy Consumers (“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.
3. **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.
4. **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.
5. **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.
6. **Public Service Company of Oklahoma, 2008 (Cause No. 08-144)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s general rate case application to address revenue requirement and rate design issues to establish prospective cost-of-service based rates.
7. **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.
8. **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.
9. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334)** – Participating as an expert witness on behalf of the Cities² in EGSI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
10. **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.

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

2 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

11. **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.
12. **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.
13. **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.
14. **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.
15. **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.
16. **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.
17. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company’s use of debt equivalency in the competitive bidding process for new resources.
18. **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.
19. **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.
20. **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.
21. **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.

22. **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.
23. **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.
24. **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.
25. **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.
26. **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.
27. **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.
28. **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.
29. **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.
30. **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.
31. **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.

32. **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.
33. **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:
34. **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.
35. **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.
36. **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.
37. **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.
38. **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.
39. **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.
40. **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.
41. **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.
42. **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.

43. **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.
44. **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.
45. **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.
46. **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.
47. **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.
48. **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.
49. **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.
50. **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.
51. **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.
52. **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.

53. **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.
54. **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.
55. **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.
56. **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.
57. **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.
58. **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.
59. **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.
60. **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.

61. **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.
62. **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.
63. **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.
64. **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.
65. **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.
66. **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.
67. **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.
68. **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.
69. **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.
70. **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.
71. **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.

72. **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.