

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

**IN THE MATTER OF THE APPLICATION)
OF OKLAHOMA GAS AND ELECTRIC)
COMPANY FOR AN ORDER OF THE)
COMMISSION AUTHORIZING)
APPLICANT TO MODIFY ITS RATES,)
CHARGES AND TARIFFS FOR RETAIL)
ELECTRIC SERVICE IN OKLAHOMA)**

CAUSE NO. PUD 201500273

**RESPONSIVE TESTIMONY
OF
MARK E. GARRETT**

FILED
MAR 21 2016

COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

REVENUE REQUIREMENT ISSUES

**ON BEHALF
OF**

**OKLAHOMA INDUSTRIAL ENERGY CONSUMERS ("OIEC")
AND
OKLAHOMA ENERGY RESULTS, LLC ("OER")**

March 21, 2016

TABLE OF CONTENTS

I. Witness Identification and Purpose of Testimony	3
II. Summary of Recommendations	6
III. Rate Base Adjustments	
A. Investment Levels Updated to 6-Month Post Test Year Balance	7
1. Plant in Service	7
2. Accumulated Depreciation.....	9
3. Accumulated Deferred Income Tax	11
4. Accumulated Retirement Obligations	11
5. Customer Deposits	12
6. Materials & Supplies and Prepayments Inventories	13
7. Account 254, Other Regulatory Liabilities (Gain on Sale of Asset).....	13
8. Net Pension Benefit Obligation	16
B. Investment Levels <u>Not</u> Updated to 6-Month Post Test Year Balance.....	17
1. Coal and Gas Supply Inventories	17
2. Plant Held for Future Use.	17
IV. Operating Revenue Adjustments	
A. Gain on Sale of Utility Assets Adjustment	18
B. Customer Load Growth Adjustment	19
V. Operating Expense Adjustments	
A. Payroll Expense Adjustments.....	21
B. Annual Incentive Compensation Expense Adjustment	28
C. Long-Term Stock Incentive Plan Adjustment.....	43
D. Supplemental Employee Retirement Plan Adjustment	49
E. Ad Valorem Tax Expense Adjustment	54
F. Vegetation Management Expense Adjustment.....	55
G. Corporate Cost Allocation Adjustment	59
VI. Depreciation and Amortization Expense Adjustments	
A. Adjustment to Apply OIEC/OER Rates to 6-Month Plant Balances	61
B. Adjustment to Amortize Stranded Legacy Meters over 15-Year Life	61
VII. Adjustments Proposed by Other OIEC/OER Witnesses	63
VIII. Conclusion.....	64
Exhibits	Attached

I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

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

2 A: My name is Mark E. Garrett. My business address is 50 Penn Place, 1900 N.W.
3 Expressway, Suite 410, Oklahoma City, Oklahoma 73118.

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

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

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

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

1 personnel. In utility regulation, I served as an auditor in the Public Utility Division of
2 the Oklahoma Corporation Commission from 1991 to 1995. In that position, I managed
3 the audits of major gas and electric utility companies in Oklahoma. Since leaving the
4 Commission, I have testified in numerous rate cases and other regulatory proceedings on
5 behalf of various customer interveners.

6
7 **Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THIS COMMISSION**
8 **IN PROCEEDINGS DEALING WITH REVENUE REQUIREMENT ISSUES?**

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

11
12 **Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?**

13 A: I am appearing on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) and
14 Oklahoma Energy Results, LLC (“OER”).

15
16 **Q: WHO IS OIEC?**

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

20
21 **Q: WHAT IS OIEC’S INTEREST IN THIS PROCEEDING?**

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

10

11 **Q: WHO IS OER?**

12 A: Oklahoma Energy Results, LLC is an entity comprised of large industrial and
13 independent power production members. OER's interest in this proceeding is that fair,
14 just and reasonable rates are established and that rates arise from prudent utility actions.

15

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

17 A: The purpose of my testimony is to address various revenue requirement issues identified
18 in OG&E's rate case application and to provide the Commission with recommendations
19 for the resolution of these issues. I also sponsor *Exhibit MG 2* included with this
20 testimony, in which the overall impact of OIEC's and OER's revenue requirement
21 recommendations is set forth. In total, OIEC's and OER's recommendations result in a
22 rate decrease of \$36.6 million, as outlined in the following section of testimony.

II. SUMMARY OF RECOMMENDATIONS

OG&E'S Proposed Rate Increase \$ 92,494,692

OIEC/OER Proposed Adjustments:

Rate Base Adjustments

Adjust Plant Investment to 6-Month Level	\$ 1,440,487
Adjust Accumulated Depreciation to 6-Month Level	3,330,536
Adjust Plant Held for Future Use	(124,633)
Adjust ADFIT to 6-Month Level	84,794
Adjust Customer Deposits to 6-Month Level	(132,667)
Adjust ARO to 6-Month Level	(403,104)
Adjust Materials and Supplies to 6-Month Level	(92,320)
Adjust Prepayments to 6-Month Level	9,175
Adjust Gain on Sale (Acct 254) to 6-Month Level	(109,051)
Adjust Net Pension Asset Balance to 6-Month Level	(744,562)

Cost of Capital

Apply OIEC/OER Cost of Capital Adjustments \$ (45,476,468)

Revenue and Expense Adjustments

Adjust Customer Growth to 6-Month Cutoff	\$ (5,375,062)
Recognize Gain on Sale of Utility Assets	(591,808)
Reverse OG&E Payroll Adjustment	(5,097,319)
Adjust Payroll Taxes for Proposed Payroll Adjustments	(357,881)
Remove 50% of Annual Incentive Plan	(7,104,554)
Remove 50% of Payroll Tax on Annual Incentive Plan	(498,740)
Remove 100% of Executive Incentive Plan	(5,505,652)
Remove Supplemental Executive Retirement Plan	(1,713,195)
Reverse Adjustment for Affiliate Expense Allocation	(5,579,128)
Reverse OG&E Estimated Ad Valorem Adjustment	(4,166,889)
Limit Vegetation Management to 5-year Spending Level	(5,983,404)

Depreciation and Amortization Expense Adjustments

Amortize Stranded Smart-Grid Meters over 15 Years	\$ (3,679,140)
Adjust Expense for OIEC/OER Depreciation Rates	(37,298,897)

Total of OIEC/OER Adjustments \$ (125,169,481)

OIEC/OER Proposed Rate Decrease \$ (32,674,789)

III. RATE BASE ADJUSTMENTS

III. A. INVESTMENTS UPDATED TO 6-MONTH POST TEST YEAR BALANCES

(1) PLANT IN SERVICE

1 **Q: ARE YOU PROPOSING AN ADJUSTMENT TO THE COMPANY'S PRO**
2 **FORMA PLANT IN SERVICE?**

3 A: Yes. In Oklahoma, the Commission is required by law (Title 17 § 284) to give effect to
4 known and measurable changes that occur within six months of test year end. In this
5 application, the test year end is June 30, 2015 and the 6-month cut-off for post-test year
6 adjustments is December 31, 2015. My adjustment updates Plant in Service accounts
7 through this date.

8
9 **Q: HOW IS YOUR ADJUSTMENT CALCULATED TO REFLECT ACTUAL**
10 **INVESTMENT LEVELS AT DECEMBER 31, 2015?**

11 A: In general, the adjustment is calculated by comparing the Company's requested level of
12 Plant in Service in its Application to the actual account balance at December 31, 2015.
13 The Company's requested level includes actual Plant in Service balances at test year end,
14 an estimated amount the Company expected to be in service within six months after test
15 year. My adjustment reflects the *actual* plant balances at December 31, 2015.

16
17 **Q: IS THE ADJUSTMENT TO ACTUAL BALANCES AT THE 6-MOTNH CUT OFF**
18 **THE GENERALLY ACCEPTED APPROACH?**

19 A: Yes. Title 17 §284 was enacted in 1996. The first litigated case in which this approach

1 was adopted was in ONG's 2004 rate case, Cause No. PUD 200400610, in which the
2 ALJ adopted the approach, no party appealed the recommendation, and the Commission
3 accepted and approved the ALJ's recommendation. In that proceeding, after a hearing
4 on the merits, the ALJ updated ONG's Plant in Service and Accumulated Depreciation
5 balances through the six month period following test year end. Projects still in the CWIP
6 accounts at that time were specifically excluded. In OG&E's 2005 rate case, PUD
7 200500151, the Commission again updated the Plant and Accumulated Depreciation
8 balances to six months after test year end and appropriately excluded CWIP on the books
9 at that time. Also, in PSO Cause Nos. PUD 200600285 and PUD 200800144, the
10 Commission also followed this approach. OG&E's last rate case, Cause No. PUD
11 201100087, was a settled case. However, the ALJ recommended this approach in her
12 Report prior to the Parties' settlement of the case.

13
14 **Q: WHY IS AN ADJUSTMENT TO THE COMPANY'S REQUESTED LEVEL**
15 **REQUIRED?**

16 A: The actual updated balances for the six month cut off are not available when the
17 Company files its Application. As a result, the amounts the Company used in its
18 Application include *estimated* projected balances as of the six month cutoff date. In
19 response to data requests, the Company now has provided the actual account balances.
20 The adjustments I propose are required to reflect actual account balances, rather than the
21 Company's estimated balances as of the six month cutoff.

1 **Q: IS YOUR PROPOSED TREATMENT – THAT WAS ACCEPTED IN PREVIOUS**
2 **ONG, OG&E AND PSO RATE CASES – CONSISTENT WITH BOTH**
3 **OKLAHOMA LAW AND SOUND RATEMAKING PRINCIPLES?**

4 A: Yes. The proposed treatment satisfies the statutory requirement to give effect to known
5 and measurable changes occurring within six months of test year end because both the
6 Plant in Service balances and the Accumulated Depreciation balances are updated to the
7 end of the six month post test year period. The adjustment to reflect December 31, 2015
8 Plant in Service balance is set forth below. The detailed calculations are shown at
9 *Exhibit MG 2.1* attached to this testimony.

Description	OG&E's Requested Balance	Actual Balance (at 12-31-2015)	OIEC/OER Adj Increase (Decrease)	Oklahoma Jurisdictional Amount
Plant in Service	\$9,617,401,108	\$9,631,284,933	\$13,883,825	\$12,473,690

III. A. (2) ACCUMULATED DEPRECIATION

10 **Q. HAVE YOU PROPOSED AN ADJUSTMENT TO THE COMPANY'S PRO**
11 **FORMA ACCUMULATED DEPRECIATION ACCOUNT BALANCE?**

12 A: Yes. When the investment in Plant in Service is updated to the actual levels as of the six
13 month cut off, it is also necessary to adjust changes in the investment levels related to
14 off-setting accounts such as Accumulated Depreciation and Accumulated Deferred
15 Income Tax (ADIT). These adjustments have been consistently accepted by the
16 Commission in recent rate case proceedings, and are consistent with Oklahoma law.
17 (Title 17 § 284). The necessary adjustment to reflect the actual December 31, 2015

1 Accumulated Depreciation balance is set forth below. The detailed calculations and
2 supporting references are shown at *Exhibit MG 2.1* attached to this testimony.

Description	OG&E's Requested Balance	Actual Balance (at 12-31-2015)	OIEC/OER Adj Increase (Decrease)	Oklahoma Jurisdictional Amount
Accumulated Depreciation	\$(3,672,618,649)	\$(3,640,581,266)	\$32,037,383	\$28,840,304

3 This adjustment updates the Company's Accumulated Depreciation balance to the
4 December 15, 2015 levels, and is necessary to give effect to the known and measurable
5 decrease in the Accumulated Depreciation balance that occurred within six months of
6 test year end.

7
8 **Q: THE PROPOSED ADJUSTMENTS TO BOTH PLANT IN SERVICE AND**
9 **ACCUMULATED DEPRECIATION RESULT IN INCREASES TO RATE BASE.**
10 **WHY IS THIS?**

11 A: This is the adjustment necessary to reflect the Company's actual account balances as of
12 the cutoff date. Because the Accumulated Depreciation account is an offset to the Plant
13 in Service account, it seems counterintuitive that the adjustments to both accounts would
14 result in an increase to rate base. However, the necessary adjustments to each of these
15 accounts may be positive or negative in a given cause, depending on the relationship
16 between Company's *estimated* account balances and its *actual* account balances. In the
17 current cause, the Company's estimates were conservative for both accounts and, as a
18 result, increases to rate base for both Plant in Service and Accumulated Depreciation are
19 needed to adjust the Company's estimated balances to actual levels.

III. A. (3) ACCUMULATED DEFERRED INCOME TAXES (ADIT).

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 December 31, 2015 levels. This adjustment is necessary to give effect to
5 the known and measurable increase in the deferred tax balances that occurred within six
6 months of test year end. When additions to the investment levels in Plant in Service are
7 recognized through the six month cut off, changes in the investment levels related to
8 ADIT must be recognized as well. This adjustment has been accepted previously by the
9 Commission, and is consistent with Oklahoma law (Title 17 § 284). The necessary
10 adjustment to reflect the actual December 31, 2015 ADIT balance is set forth below.
11 The detailed calculations and supporting references are shown at *Exhibit MG 2.1*
12 attached to this testimony.

Description	OG&E's Requested Balance	Actual Balance (at 12-31-2015)	OIEC/OER Adj Increase(Decrease)	Oklahoma Jurisdictional Amount
ADIT	\$(1,481,089,618)	\$(1,480,273,771)	\$815,847	\$734,262

III. A. (4) ACCUMULATED RETIREMENT OBLIGATIONS

13 **Q: IS AN ADJUSTMENT NECESSARY TO UPDATE THE ACCUMULATED**
14 **RETIREMENT OBLIGATIONS TO THE SIX MONTH CUTOFF BALANCE?**

15 A: Yes. An adjustment to the Company's Accumulated Retirement Obligations ("ARO")
16 account is necessary to give effect to the known and measurable changes that occurred
17 within six months of test year end. Adjustments to recognize six-month updates to the

1 ARO account have been consistently accepted by the Commission in recent rate case
 2 proceedings, and are consistent with Oklahoma law (Title 17 § 284). The updated ARO
 3 account balance can be found in the Company's response to AG 1-10 (Supplemental).
 4 The adjustment necessary to reflect the actual December 31, 2015 Accumulated
 5 Retirement Obligation account balance is set forth below. The detailed calculations are
 6 shown at *Exhibit MG 2.1* attached to this testimony.

Description	OG&E Requested Balance	Actual Balance (at 12-31-2015)	OIEC/OER Adj Increase (Decrease)	Oklahoma Jurisdictional Amount
AROs	\$(59,452,952)	\$(63,292,180)	\$(3,839,228)	\$(3,490,626)

III. A. (5) CUSTOMER DEPOSITS

7 **Q: HAVE YOU PROPOSED AN ADJUSTMENT TO CUSTOMER DEPOSITS?**

8 A: Yes. An adjustment to the Company's Customer Deposits account is necessary to give
 9 effect to the known and measurable changes that occurred within six months of test year
 10 end, as has been accepted by the Commission in recent rate case proceedings, and is
 11 consistent with Oklahoma law. The updated Customer Deposits account balance can be
 12 found in the Company's response to AG 1-2 (Supp 4). The adjustment necessary to
 13 reflect the actual December 31, 2015 balance is set forth in the table below. The detailed
 14 calculations are shown at *Exhibit MG 2.1* attached to this testimony.

Description	OG&E Requested Balance	Actual Balance (at 12-31-2015)	OIEC/OER Adj Increase (Decrease)	Oklahoma Jurisdictional Amount
Customer Deposits	\$(75,933,115)	\$(77,179,247)	\$(1,246,132)	\$(1,148,809)

III. A. (6) MATERIALS & SUPPLIES AND PREPAYMENTS INVENTORIES

1 **Q: ARE YOU PROPOSING ADJUSTMENTS TO UPDATE BOTH THE**
2 **MATERIALS & SUPPLIES ACCOUNT AND THE PREPAYMENTS ACCOUNT**
3 **TO INCLUDE MONTHLY DATA THROUGH THE SIX MONTH CUTOFF?**

4 A: Yes. The Company has provided monthly data reflecting an additional six months of
5 activity in these accounts to calculate averages through December 31, 2015. This data is
6 reflected in the Company's response to AG 1-2 Supplement 4. I have utilized this data
7 to prepare updated 13-month averages of these accounts to be included in rate base. The
8 necessary adjustments to reflect the 13-month averages for the period ending December
9 31, 2015 are set forth below. The detailed calculations are shown at *Exhibit MG 2.1*
10 attached to this testimony.

Description	OG&E's Requested Balance	Actual Balance (at 12 31 2015)	OIEC/OER Adj Increase (Decrease)	Oklahoma Jurisdictional Amount
Materials & Supplies	\$77,250,587	\$76,378,417	\$(872,170)	\$(799,431)
Prepayments	\$3,793,005	\$3,880,336	\$87,331	\$79,454

III. A. (7) ACCOUNT 254 - OTHER REGULATORY LIABILITIES

11 **Q: PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT FOR A 6-MONTH**
12 **UPDATE TO ACCOUNT 254.**

13 A: Account 254 - Other Regulatory Liabilities, includes the amounts of regulatory liabilities
14 established with credits which would have been included in net income, or other
15 comprehensive income, but for the fact that the items should be spread over different
16 periods for the purpose of developing rates. For example, Gains on the Sale of Utility

1 Assets are credited to this account and amortized into future rates over some prescribed
2 period. At the end of the test year, the balance in this account was zero, but at the end of
3 the 6-month update period, the balance in the account was \$962,500.¹ The credit balance
4 in this account should be included in rate base because it falls within the statutorily
5 prescribed update period.

6
7 **Q: WHAT DOES THE \$982,500 BALANCE REPRESENT?**

8 A: The balance represents the gain on a sale of a rotor from the McClain plant to General
9 Electric. The gain on the sale was recorded in Account 254 on December 31, 2015.

10
11 **Q: HOW ARE GAINS ON SALES OF UTILITY PROPERTY GENERALLY
12 TREATED FOR RATEMAKING PURPOSES?**

13 A: The proper regulatory treatment of gains on sales of regulatory assets is fairly well
14 settled. In the case of normal retirements, there is virtually no debate since any gain or
15 loss that may result is routinely passed on to ratepayers through the normal accounting
16 entries to the accumulated depreciation reserve. Any disagreements that might arise
17 regarding the appropriate ratemaking treatment of gains generally arise only in those
18 instances when the gain is sizable. In those situations, the utility may lay claim to the
19 gain, or some portion of it, based on notions that ownership of the underlying asset
20 entitles the utility to any gain that may result from its sale. These same notions,
21 however, are noticeably absent when regulated assets are sold at a loss.

22 The National Regulatory Research Institute (NRRI) conducted a comprehensive

¹ See Company's Response to OIEC 13-1 Attachment.
Responsive Testimony of Mark E. Garrett
Cause No. PUD 201500273

1 study in 1994 to determine how state commissions treated gains on sale of regulated
2 assets.² The results of the study showed that most states allocated the gain entirely to
3 ratepayers. In fact, of states with a generic policy toward dispositions of gains, only one
4 state allocated the gain to shareholders, and then only if the gain related to an operating
5 unit. In the NRRI survey, the most frequently cited rationale, in 30 jurisdictions
6 including Oklahoma, was that gains should accrue to ratepayers for property included in
7 rate base.³ I am not aware of any reason why the traditional treatment of gains on sales
8 of utility property would change, or has changed, since the date NRRI conducted its
9 study.

10
11 **Q: WHAT DO YOU RECOMMEND WITH RESPECT TO THE GAIN ON THE**
12 **SALE OF THE MCCLAIN ROTOR TO GENERAL ELECTRIC?**

13 A: I recommend that the gain be included in rate base (as a credit to rate base) and that the
14 gain be refunded to ratepayers through a 2-year amortization of the balance.⁴ The
15 amount of gain to be included in rate base is a credit balance of \$962,500, with an
16 Oklahoma jurisdictional amount of \$944,309. The calculations are shown below and at
17 *Exhibit MG 2.1* attached to this testimony.

Description	Actual Balance (at 12-31-2015)	OIEC/OER Adj Increase (Decrease)	Oklahoma Jurisdictional Amount
ACCT 254-Gain on Sale of Assets	\$(962,500)	\$(962,500)	\$(944,309)

² NRRI 94-17, State Public Service Commission Disposition of the Gain on Sale of Utility Assets, August 1994.

³ NRRI 94-17, Table 10 at page 10.

⁴ I used a two-year amortization to correspond with the expected next rate case filing of the Company.

III. A. (8) NET PENSION BENEFIT OBLIGATION BALANCE

1 Q: IS AN ADJUSTMENT NECESSARY TO UPDATE THE NET PENSION
2 BENEFIT OBLIGATION BALANCE TO THE 6-MONTH CUTOFF DATE?

3 A: Yes. In its application the Company combined the asset and liability balances for its
4 Prepaid Pension accounts and its Other Post-Employment Benefits (“OPEB”) accounts
5 in a single item labeled, Net Pension Benefit Obligation. The balance included in pro
6 forma rate base for these combined items is \$54,974,401, as shown at Schedule B-2, line
7 16. The amount included in rate base reflects the regulatory asset and liability account
8 balances for these post-retirement benefits at test year end. By December 31, 2015, the
9 balances in these accounts had changed significantly.⁵ As a result, the balances in these
10 accounts at the 6-month cut-off date should be reflected in rate base. The table below
11 shows the adjustments needed to reflect the 6-month updated balances.

Description	OG&E’s Requested Balance	Actual Balance (at 12-31-2015)	OIEC/OER Adj Increase (Decrease)	Oklahoma Jurisdictional Amount
Prepaid Pension Account 182.3	\$254,186,790	\$242,232,668	\$(11,954,122)	
ADIT on Prepaid Pension Accounts	\$(66,562,736)	\$(55,737,561)	\$10,825,175	
OPEB Liability Account 228.3	\$(174,015,692)	\$(179,925,299)	\$(5,909,607)	
ADIT on OPEB Accounts	\$41,366,040	\$41,421,563	\$55,523	
Total	\$54,974,401	\$47,991,371	\$(6,983,030)	\$(6,447,432)

12 The detailed calculations for this adjustment are set forth at Exhibit MG 2.2 attached to
13 this testimony.

14
⁵ See OG&E’s Responses to OIEC 13-1 Attachment and AG 19-5 Attachment.

1 **III. B. ACCOUNTS NOT UPDATED TO 6-MONTH POST TEST YEAR CUTOFF**

2 **Q: ARE THERE CERTAIN RATE BASE ACCOUNTS THAT HAVE NOT BEEN**
3 **UPDATED TO THE SIX MONTH CUTOFF DATE?**

4 A: Yes. Three accounts need not be updated to the 6-month cutoff. These accounts are: (1)
5 Coal Supply Inventory, (2) Gas Supply Inventory and (3) Plant Held for Future Use.
6 The two fuel inventory accounts—coal and gas—are established on a calculated supply
7 basis. As such, these accounts need not be updated to their actual 6-month post-test year
8 levels. Likewise, Plant Held for Future Use does not require a 6-month update because
9 the entire balance of this account should be removed from rate base as this account is
10 comprised of costs that are not used and useful at this time.

11
12 **Q: PLEASE DESCRIBE THE ISSUE RELATED TO THE COMPANY’S PLANT**
13 **HELD FOR FUTURE USE ACCOUNT.**

14 A: This account contains costs of land purchases and land rights that the Company is
15 holding for future development and expansion. Because the assets in this account are not
16 used and useful at this time, the entire balance should be removed from rate base. Plant
17 Held for Future Use included in OG&E’s pro forma rate base is \$1,497,777, as shown on
18 Schedule B-2. The necessary adjustment is set forth below and detailed calculations are
19 shown at *Exhibit MG 2.1* attached to this testimony.

Description	OG&E’s Requested Balance	Actual Balance Used and Useful	OIEC/OER Adj Increase (Decrease)	Oklahoma Jurisdictional Amount
Plant Held for Future Use	\$1,497,777	\$0	\$(1,497,777)	\$(1,079,239)

IV. OPERATING REVENUE ADJUSTMENTS

1 **IV. A. GAIN ON SALE OF UTILITY ASSETS**

2 **Q: PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT TO INCLUDE GAINS**
3 **ON SALE OF UTILITY ASSETS IN RATES.**

4 A: In a prior section of this testimony, I explained how OG&E sold a rotor from the
5 McClain plant to General Electric last year and recorded the gain from that sale to
6 Account 254 in December of 2015. I explained that the widely-accepted treatment of
7 gains from the sales of utility property is to refund those gains to ratepayers over some
8 prescribed period of time determined by the Commission. I recommended that the
9 balance in Account 254 be included in rate base and amortized into rates over a 2-year
10 period. The adjustment in the prior section of testimony was to include the balance in
11 Account 254 in rate base. The adjustment here is to include the amortization of that
12 balance in rates over a 2-year period.

13
14 **Q: WERE THERE OTHER GAINS FROM SALES OF UTILITY PROPERTY IN**
15 **THE TEST YEAR?**

16 A: Yes. OG&E also recognized a gain on the sale of distribution facilities to the Choctaw
17 Nation on June 30, 2015 in the amount of \$119,654.⁶ This gain should also be included
18 in rates. The entire amount of this gain should be recognized in one year (rather than a
19 2-year amortization) because it appears to be representative of a normal level of gains
20 recognized by OG&E over the last several years.

⁶ See Company's response to OIEC 3-25.

1 **Q: HOW IS YOUR ADJUSTMENT CALCULATED?**

2 A: The adjustment is calculated by adding half of the gain from the sale of the McClain
3 rotor to General Electric with the entire gain from the sale of distribution facilities to the
4 Choctaw nation. The adjustment is set forth below and can be seen at *Exhibit MG 2.11*.

OIEC/OER Adjustment to Include Gains on Sales of Utility Property	
Description	Okla Juris Amt
2-Year Amortization of Rotor Sale to General Electric	\$(472,154)
Sale of Distribution Facilities to Choctaw Nation	\$(119,654)
OIEC/OER Adjustment for Gains on Sale	\$(591,808)

IV. B. 6-MONTH REVENUE UPDATE FOR LOAD GROWTH

5 **Q: PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT FOR A 6-MONTH**
6 **REVENUE UPDATE FOR LOAD GROWTH.**

7 A: This adjustment updates a vital component of the revenue requirement formula and is
8 necessary to fully comply with the requirements of Title 17 § 284 to recognize known
9 and measurable changes that occur within six months of test year end. The three major
10 components of the revenue requirement formula are: (1) investment levels, (2) revenue
11 levels, and (3) expense levels. In this case, I have updated the investment levels to the 6-
12 month cutoff with all of the rate base adjustments to plant, accumulated depreciation,
13 accumulated deferred income tax, accumulated retirement obligations, customer
14 deposits, prepayments and inventory levels. I have also updated expense levels through
15 adjustments to the major expense categories including payroll expense, property tax
16 expense and depreciation expense. When investment levels (rate base) and expense

1 levels are adjusted for known and measurable changes, revenue levels must also be
2 adjusted to correctly synchronize the three major components for the revenue
3 requirement formula. In other words, to fully comply with the requirements of Title 17 §
4 284, known and measurable changes in the revenue levels must be recognized.

5
6 **Q: TO COMPLY WITH TITLE 17 § 284, MUST EVERY INVESTMENT, EXPENSE**
7 **AND REVENUE ACCOUNT BE UPDATED TO DECEMBER 31, 2015?**

8 A: No. Practically speaking, only those accounts with known and measurable changes of a
9 material amount need to be updated. In this case, however, the known and measurable
10 change in load growth through the 6-month update period is a material change that
11 should be recognized.

12
13 **Q: HOW DID YOU DETERMINE THE AMOUNT OF LOAD GROWTH THAT**
14 **OCCURRED THROUGH THE DECEMBER 31, 2015 6-MONTH CUT OFF?**

15 A: OG&E provided the amount of growth that occurred on the system through the 6-month
16 update period in its Supplemental response to AG 2-10. The increase in Oklahoma
17 revenues calculated by OG&E from load growth through December 31, 2015 was
18 \$17,886,497.

19
20 **Q: HOW IS YOUR ADJUSTMENT CALCULATED?**

21 A: The adjustment is calculated by comparing OG&E's load growth adjustment through the
22 December 31, 2015 of \$17,886,497 with OG&E's load growth adjustment through the

1 test year end, of \$12,511,435, which was included in the Application at W/P H-2b
 2 Summary. This adjustment increases revenues by \$5,375,062 and reduces OG&E's
 3 requested rate increase by the same amount. The adjustment is shown below and at
 4 *Exhibit MG 2.9*.

OIEC/OER Adjustment for Load Growth through December 31, 2015	
Description	Okla Juris Amt
OG&E's Load Growth Adjustment through December 31, 2015	\$17,886,497
OG&E's Load Growth Adjustment through June 30, 2015	\$12,511,435
OIEC/OER Adjustment for Growth through December 31, 2015	\$ (5,375,062)

V. OPERATING EXPENSE ADJUSTMENTS

V. A. 6-MONTH UPDATE TO PAYROLL EXPENSE

5 **Q: PLEASE DESCRIBE OG&E'S PROPOSED PAYROLL ADJUSTMENT.**

6 A: OG&E's proposed payroll adjustment is a two-part adjustment. The first part annualizes
 7 payroll expense at test year end by multiplying the final two-week pay period in June
 8 2015 by 26 to arrive at an annualized payroll level. The second part of the adjustment
 9 then increases that amount by another 3% approximately for pay raises that OG&E
 10 expects will be awarded in 2016. Payroll taxes are then added to the adjustment to arrive
 11 at a total requested increase in payroll costs of \$6,047,223.⁷

12

⁷ See Direct Testimony of Jason Thenmadathil at page 11, lines 15-30. The \$6,047,223 is comprised of \$5,650,503 in payroll expense plus \$396,720 in payroll taxes. These amounts and calculations can be seen at *Exhibit MG 2.4*.

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

2 A: No. Regarding the first part of the adjustment, an annualization that multiplies a final
3 pay period by 12 or 26 is only appropriate if the final pay period is representative of
4 ongoing levels. Here, that is not the case. If the final 2-week pay period in June 2015
5 was representative of ongoing levels, then payroll costs would have increased during the
6 6-month period following the annualization. However, as will be discussed below, that
7 is not what happened. Regarding the second part of the adjustment, an additional
8 increase for pay raises based on the nominal amount of the pay raises is almost never
9 appropriate because payroll levels almost never increase by the nominal amount of the
10 pay raise. In other words, a 3% pay raise will almost never result in a 3% increase in
11 payroll expense levels. The actual increase amount associated with a nominal pay raise
12 is not known and measurable because too many other factors impact the overall change
13 in payroll expense. These factors include: (1) the normal turnover of employees in a
14 company the size of OG&E, where employees come onto and leave the payroll registers
15 on a regular basis, with retiring employees taking higher salaries levels off the system
16 and new employees coming on at lower pay scale levels; (2) workforce reorganizations,
17 where significant reductions in the workforce levels are achieved through new
18 technologies or other innovations; (3) productivity gains, where smaller reductions in the
19 workforce levels are achieved on an ongoing basis through increased employee
20 efficiencies; and (4) capitalization ratio changes, where more payroll costs are
21 capitalized (rather than expensed) during a period of capital expansion – such as OG&E

1 is experiencing now.⁸ All of these factors impact overall payroll cost levels as much or
2 more than pay raises do. Yet, regulated utilities, in their rate cases, often want to only
3 acknowledge the pay raise impacts while ignoring the impacts of these other important
4 changes.

5
6 **Q: HOW SHOULD TEST YEAR PAYROLL LEVELS BE ADJUSTED?**

7 A: First, test year payroll levels should only be adjusted if it is shown that the test year
8 levels are not reasonable for setting rates. Thus, if test year levels are reflective of
9 ongoing payroll levels, no adjustment is needed. Here, we can compare the payroll
10 levels actually paid during the 6-month post-test year period with the test year levels to
11 see if actual payroll costs are changing significantly. More importantly, we can compare
12 actual payroll *expense* levels during the 6-month post-test year period with test year
13 *expense* levels.

14
15 **Q: DID YOU MAKE THIS COMPARISON?**

16 A: Yes. In response to OIEC 1-4 Supplement, OG&E provided actual payroll costs for the
17 test year and for the year ended December 31, 2015. Test year payroll expense was
18 \$102,930,518 and payroll expense for the 12-month period ending December 31, 2015
19 was \$103,021,765. Thus, the increase in 2015 payroll expense over test year expense
20 was only \$91,247. This amounts to a 1/10th of 1% increase, which is not a significant

⁸ As utilities add plant, a portion of the payroll costs are capitalized into the cost of the new plant. The rest of the payroll costs are expensed and that expense level is what we use to set rates. If a utility is in a capital expansion phase, its capitalization ratio will generally increase. This will make expense levels go down, even if overall payroll costs are going up. Thus, a 3% increase in the capitalization ratio alone can offset a nominal 3% pay raise.

1 enough change to require the adjustment OG&E has proposed.

2 At the Holding Company level, test year payroll expense (allocated to OG&E)
3 was \$31,564,686 and payroll expense for the 12-month period ending December 31,
4 2015 dropped to \$31,187,015, a decrease of \$377,670, (or 1.2 %) in payroll expense.⁹
5 Thus, when OG&E and Holding Company payroll expense are considered together, total
6 payroll expenses actually decreased by \$286,423 during the 6-month period after test
7 year end.¹⁰ This is a far cry from the \$5,650,503 million increase sought by OG&E.¹¹ In
8 my opinion, the actual payroll expense levels achieved during the 6-month period after
9 test year end demonstrate that the test year levels are reasonable for the purpose of
10 setting rates. In fact, because OG&E's actual payroll expenses have decreased, a
11 reasonable cushion of \$286,423 is already built into rates if the Company's test year
12 levels are used.

13
14 **Q: PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT.**

15 A: My adjustment reverses OG&E's proposed payroll expense increases and reinstates the
16 test year expense level as the reasonable level for setting rates. This recommendation is
17 based on the fact that actual payroll expense levels achieved during the 6-month post-test
18 year period ending December 31, 2015 were slightly lower than the test year levels.

19
20 **Q: DO YOU AGREE WITH THIS ADJUSTMENT?**

⁹ See OIEC 1-3 Supplemental.

¹⁰ OG&E's overall payroll decrease is calculated as follows: \$91,247 + (\$377,670) = (\$286,423).

1 A: Yes. In my opinion, this is a reasonable method of calculating known and measurable
2 payroll changes for the post-test year period.

3

4 **Q: WHY IS THIS APPROACH REASONABLE UNDER THE CIRCUMSTANCES?**

5 A: This approach avoids the uncertainties associated with a payroll annualization
6 adjustment, where payroll levels during the rate-effective period are projected by merely
7 multiplying the final pay period by the number of pay periods in a year. The
8 annualization approach assumes that the final pay period is representative of ongoing
9 payroll levels, which may or may not be accurate. This recommended approach avoids
10 these uncertainties by picking up the Company's actual payroll expenditures during the
11 6-month post-test year period.

12

13 **Q: WOULD A PAYROLL ANNUALIZATION AT DECEMBER 31, 2015 BE**
14 **APPROPRIATE IN THIS CASE?**

15 A: No. A payroll annualization six months after test year end would effectively be
16 projecting payroll costs for the next 12-month period, which is getting well beyond the
17 test year. Even if it were appropriate to project costs effectively 18 months beyond the
18 test year, a simple payroll annualization, with nothing more, is inadequate. A payroll
19 annualization by itself does not take into account the many other changes in the payroll
20 levels discussed above. At a minimum, productivity gains would have to be
21 incorporated into a payroll projection. According to the Bureau of Labor Statistics,

¹¹ OG&E requests \$5,650,503 in payroll expense, plus \$396,720 in payroll taxes, for a total of \$6,047,223. These amounts and calculations can be seen at *Exhibit MG 2.4*.

1 productivity gains in the manufacturing sector have averaged about 2.1% from 2007 -
 2 2015.¹² This means that any projected payroll cost increases from an annualization at
 3 December 31, 2015 would have to be offset with a 2.1% reduction for productivity,
 4 which would effectively eliminate any annualization increase. In my opinion, the better
 5 approach is to use the actual results from the 6-month post-test year period to set pro
 6 forma payroll expense. Here, since actual costs for the 12-month period ending
 7 December 31, 2015 are actually slightly lower than the test year 12-month period ending
 8 June 30, 2015, OG&E's proposed adjustment to increase test year expense is not needed.
 9

10 **Q: WHAT IS THE IMPACT OF OIEC/OER'S PAYROLL ADJUSTMENT?**

11 A: This adjustment removes OG&E's requested increase of \$6,047,223, which is comprised
 12 of \$5,650,503 for payroll expense and \$396,720 for payroll taxes. These adjustments
 13 and the applicable Oklahoma jurisdictional amounts are set forth below. The
 14 calculations can be seen at *Exhibit MG 2.4*.

Description of Adjustment	OIEC/OER Adjustment	Oklahoma Jurisdictional Amount
Remove OG&E's Proposed Payroll Expense Increase	\$(5,650,503)	\$(5,097,319)
Remove OG&E's Proposed Payroll Taxes Increase	(396,720)	(357,881)
Total	\$(6,047,223)	\$(5,455,200)

¹² Bureau of Labor Statistics: Productivity change in the manufacturing sector from 1987-2015 is as follows:

1987-1990	1.5
1990-2000	4.1
2000-2007	4.7
2007-2015	2.1

Updated: March 3, 2016.

1 Q: DOES YOUR ADJUSTMENT TAKE INTO ACCOUNT OVERTIME PAYROLL
2 EXPENSE?

3 A: No. Overtime costs generally fluctuate year to year and are not typically considered by
4 regulators for setting prospective rates. If overtime expense for the December 31, 2015
5 period were added to regular payroll expense and then compared to test year expense
6 levels, for both OG&E and the Holding Company, the overall increase at December 31,
7 2015 would be \$774,679, which is much less than the \$5,650,503 requested by the
8 Company. If overtime costs are included in the analysis, the adjustment to reduce
9 OG&E's requested increase to the actual increase at December 31, 2015 would be
10 \$4,875,824 for payroll expense and \$342,330 for payroll taxes. OIEC's recommended
11 alternative adjustment that includes overtime expense is set forth below, and can be seen
12 at *Exhibit MG 2.4*.

OIEC/OER Alternative Adjustment to Reflect Payroll Expense with Overtime at 12-31-15 Levels		
Description	OIEC/OER Adjustment	Oklahoma Jurisdictional Amount
Remove OG&E's Proposed Payroll Expense Increase w/Overtime	4,875,824	4,398,481
Remove OG&E's Proposed Payroll Taxes Increase w/Overtime	342,330	308,816
Total	\$5,218,154	\$4,707,297

V. B. ANNUAL INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

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

3 A. OG&E provides an annual cash incentive compensation plan to all employees called the
4 Teamshare plan. The Company seeks to include \$15,427,914 in rates for annual
5 incentive plan costs.

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 is consistent
10 with the longstanding treatment of annual incentive compensation plans by this
11 Commission. This recommended sharing of Teamshare costs between the Company
12 and its customers reflects the fact that a major purpose of the Teamshare payments is to
13 increase the financial performance of the Company. As a general rule, regulatory
14 commissions exclude incentive compensation associated with financial performance.¹³

15

¹³ See ALJ's Proposal for Decision in Texas PUC Docket No. 28840, Footnote 284, in reference to the CCR Initial Brief at 25, in which 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 which are provided in this testimony.

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

3 A: In most jurisdictions, the cost of incentive plans which are tied to financial performance
4 measures are excluded for ratemaking purposes. When the costs associated with these
5 plans are excluded, the rationale used by the regulators is generally based on one or more
6 of the following reasons:

7 (1) **Payment is uncertain.** Often, payment of incentive compensation is conditioned
8 upon meeting some predetermined financial goal such as achieving a certain
9 increase in earnings, reaching a targeted stock price or meeting budget objectives.
10 If the predetermined goals are not met, the incentive payment is not made, or
11 payment is made at some lesser amount. Therefore, one cannot know from year
12 to year what the level of the payment may be or whether the payment will be
13 made at all. It is generally considered inappropriate to set rates to recover a
14 tentative level of expense.¹⁴

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

¹⁴ PSO's experience with its 2008 rate case proceeding, PUD 08-144, is a good example of this problem. In 2009, AEP's below target EPS reduced the funding available for incentive compensation payments by 76.9%. Although in the Company's 2008 rate case, the Commission had included more than \$4 million in rates for incentives, the Company chose not to use all of that money to pay incentives but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

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

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

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

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

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

1 A: The results of an Incentive Compensation Survey of the 24 Western States taken by the
2 Garrett Group in 2007, and updated in 2009, 2011, and 2015, shows that a clear
3 majority of the states follow the financial-performance rule, in which incentive payments
4 associated with financial performance are excluded from rates. Some states disallow
5 incentive pay using other criteria. None of the jurisdictions surveyed allow full recovery
6 of incentive compensation through rates as a general rule. The results of the survey are
7 set forth below.

States that follow the Financial-Performance Rule:

8 **Arizona** The Commission deals with incentive compensation plans on a case by case
9 basis. Evaluation centers on the criteria of benefit to customers. This treatment
10 tends to make long-term programs harder to justify, but the same criteria are
11 used to evaluate all plans including those for executives. This treatment is set
12 forth in the most recent Epcor Water rate case.¹⁶ The current treatment
13 represents a somewhat more liberalized approach compared to Arizona's former
14 position of excluding all incentive compensation from rates.

15 **Arkansas** Excludes 100% of the long-term, equity-based plans. Short-term incentive plans
16 are evaluated to determine if they are based on financial or operational measures.
17 Operational-based plans are allowed. 50% of plans containing financial
18 measures are disallowed. Any plans based solely on the discretion of the
19 company are seen as having no direct benefit to ratepayers and are disallowed
20 100%. Settlements in recent cases have upheld this treatment.¹⁷ Commission
21 rulings on Incentive Compensation have remained generally consistent,
22 excluding 100% of long-term plans and 50% of the portion of short-term plans
23 that are financially based. This treatment has been qualified in recent cases
24 based on differing plan structures. In the most recent contested Entergy rate
25 case (Docket No. 13-028-U), 50% of all short-term incentive compensation was
26 excluded because the plans included a financially-based multiplier.

27 **California** The Commission has established precedence for evaluating plans based on who
28 benefits from the plans goals, ratepayer or shareholders. In CPUC Decision 00-
29 02-046, the Commission established that utilities could recover 50% of the

¹⁵ This occurred in PSO's 2008 rate case. In 2009, when AEP's EPS fell below targeted levels, the Company simply retained for its stockholders the funds that had been provided in rates for incentive plans.

¹⁶ Epcor Water, Docket No. WS-01303A-14-0010. See also APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.

¹⁷ Entergy Arkansas, Docket No. 06-101-U, Order No. 10 and Docket No. 13-028-U, Order No. 21.

1 regular employee's incentive compensation costs in rates. In the Southern
2 California Edison litigated rate case Decision 09-03-025, the Commission
3 decided that Edison's non-executive plans and 50% of the short-term executive
4 plans would be funded in rates and that 100% of the executive long-term stock
5 plans would be disallowed.¹⁸ In a recent case, A.10-07-007, staff recommended
6 that, "customer funding should be limited to the portion of the incentive plan
7 payments that are aligned with operational objective that provide customer
8 benefits. This means that 70% of AIP be funded by shareholders, and 30% be
9 funded by ratepayers." In the settlement, the Commission disallowed 50% of the
10 plan's expense.

11 **Hawaii** Incentive compensation of all types is excluded from rates. The Commission
12 upholds the position stated in Docket No. 6531 that incentives tied to company
13 income and earnings benefit stockholders, not ratepayers. The Commission
14 further stated, "...we believe that a utility employee, especially at the executive
15 level, should perform at an optimum level without additional compensation.
16 Ratepayers should not be burdened with additional costs for expected levels of
17 service."¹⁹ Utilities in Hawaii no longer petition to have incentive compensation
18 expense included in rates.

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

25 **Kansas** For officer level incentives plans, the financially-based portion is borne by the
26 shareholders and the portion supporting operational goals is allowed in rates.
27 Non-officer incentive compensation plans for workers are allowed in rates.²¹
28 The consumer advocacy branch, Citizens' Utility Ratepayer Board (CURB) has
29 consistently recommended applying the same financial/operational criteria to
30 non-officer plans as well. In the current KCPL rate case the company has
31 voluntarily excluded 100% of the performance-based plans and 50% of the

¹⁸ Southern California Edison (Application No. 07-11-011; Decision No. 09-03-025).

¹⁹ Hawaii's policy is set forth in Docket No. 6531 in the October 17, 1991 Order No. 11317. Prior Dockets in which the Commission disallowed incentive compensation include No. 3216, No. 4215, No. 4588 and No. 5114.

²⁰ 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.

²¹ This treatment is based on the 2012 KCPL rate case (12-KCPE-764-RTS) in which the short-term plan was split 50:50, and for the long-term incentives, the Commission excluded 100% of the portion based on stockholder return and 50% of the time-based restricted stock portion of the plan. Time-based plans which vest solely on the passage of time are seen as being neutral and therefore split 50:50 between shareholders and ratepayers.

1 short-term plans with an earnings-per-share qualifier. The Company also
2 removed the earnings-per-share portion of their plan for all employees.

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

8 **Minnesota** Minnesota continues to distinguish between incentive plans tied to financial
9 triggers (such as a threshold ROE) and plans tied to criteria benefitting the
10 ratepayer. Plans based on goals which benefit ratepayers are generally allowed
11 in rates, but their costs are frequently capped at a percentage of base salaries
12 such as 15% or 25%.²² Utilities are usually required to return to ratepayers any
13 portion of incentive pay that was allowed into rates and is not subsequently paid
14 out to employees. Executive and long-term IC measures are frequently more
15 closely aligned with shareholder interests and thus are not usually allowed in
16 rates.²³

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

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

26 **Nebraska** Nebraska does not have rules regarding incentive compensation and considers
27 the issue on a case by case basis. In a 2007 rate case, NG-0041, the Commission
28 disallowed 50%, directing that cost should follow benefit and stating, "However,

²² This general policy is demonstrated in recent orders in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively.

²³ Minnesota's general policy is demonstrated in CenterPoint Energy rate case G-008/GR-13-316 and the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively. See also Minnesota Power General Rate Case E002/GR/05/1428.

²⁴ See e.g., in the latest Missouri American rate case (WR-2010-0131), not only were plans based on financial goals disallowed, but incentive payments based on customer satisfaction were disallowed due to the unreasonably small sample size used to establish a positive rating (a phone survey of 927 of roughly 450,000 customers). The Commission also removed incentive payments tied to lobbying and charitable activity. In the most recent case processed, the Ameren UE rate case, the company did not seek even short-term incentive compensation tied to earnings, providing further indication that staff's practice of disallowing financial performance based incentives is accepted by the companies. All incentive compensation adjustments were made not only to expense charges, but to construction charges as well. See also Kansas City Power and Light and Empire Electric District orders on the Commission's website.

1 the Commission further finds that the nature of the objectives appear to benefit
2 both ratepayers and shareholders and it would be improper for the ratepayers to
3 bear the full cost of this benefit." The Commission also allowed in rates only the
4 actual amounts paid. In NG-0060 the Commission disallowed the entire amount
5 requested by SourceGas for cash incentives.

6 **Nevada** The Commission excludes 100% of the long-term plans and all short-term plan
7 costs directly related to financial performance.²⁵

8 **New Mexico** Incentive programs tied to measures that benefit ratepayers (such as operation
9 and safety) are allowed in rates. Programs tied to the financial performance of
10 the utility (e.g. stock price or ROE) are not allowed in rates. . This standard is
11 applied to all levels of utility employees and tends to eliminate the greater
12 portion of executive plans.²⁶ Executive incentive plans receive more scrutiny as
13 they are more likely to have financial measures. They can also be challenged if
14 the overall percentage is out of line. One major utility in New Mexico no longer
15 includes the compensation of its top 5 executives in rate applications.

16 **N. Dakota** In North Dakota, the general policy is the portion that relates to earnings of the
17 shareholders is disallowed and the rest is included. In the past, the Commission
18 has limited incentives to 15% of salary. The general approach is to determine if
19 incentive compensation is reasonable and fair based on market analysis.
20 Historically, executive incentive compensation is not allowed in rates, and is
21 typically not sought by the company.

22 **Oklahoma** The Commission excludes incentive payments tied to financial performance.
23 From a practical perspective this means that all long-term plans are excluded and
24 some portion of the annual short-term cash plan are excluded. The Commission
25 does not determine the precise portion of the annual plans tied to financial
26 measures but instead excludes 50% of the annual plans. 100% of the long-term
27 executive stock-based plans are excluded.²⁷

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

33 **S. Dakota** South Dakota considers incentive compensation on a case by case basis. Their
34 general policy is to evaluate each plan and disallow the portion based on
35 financial performance indicators. This treatment is set forth in the recent case
36 EL14-026 in which the order specifically excluded the amount "tied to the

²⁵ See e.g., PUCN's final order in Docket 11-06006.

²⁶ See Docket 07-00077-UT.

²⁷ See e.g., AEP-PSO Cause Nos. PUD 06-285 and PUD 08-144; OG&E Cause No. PUD 05-151; and
ONG Cause No. PUD 04-610.

1 Company's financial results."²⁸ Current treatment also includes disallowing both
2 executive and non-executive management incentive compensation. Several
3 utilities have whole incentive programs that hinge on whether or not the
4 company earns a certain return. These financial prerequisites cause the whole
5 plans to be excluded from rates.

6 **Texas**

7 The general rule is that incentive payments designed to improve the financial
8 performance of the utility are excluded. For example, in PUC Docket No.
9 28840,²⁹ the Commission disallowed sixty-six percent (66%) of AEP-Texas
10 Central's test year incentive payments in the amount of \$4.2 million. This was
11 the portion of the utility's incentive payments that were based on financial
12 performance measures.³⁰ Long-term stock incentives are strictly excluded.
13 At the RRC, financial incentives are excluded and customer-related
14 incentives are allowed in rates. Examples include: Atmos 9670 Order and
15 Order on Rehearing, Texas Gas Service Company 9988 Final Order,
16 Centerpoint 9902 Final Order and Centerpoint 10106 Final Order. In
17 Docket 9670 both the executive and employee plans for Atmos Mid-Tex
18 were found not to be just and reasonable because they, "advanced the
19 interest of shareholders, and [are] driven by Company earnings." None of
20 the costs of these programs were allowed in rates. In TGS Docket 9988,
21 the RRC found 100% of long-term and 90% of short-term incentives
22 expense was "unreasonable" because it was related to the financial
23 performance of ONEOK Inc. 10% of the short-term plan was allowed in
rates because it was based on safety metrics.

24 **Utah**

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

27 **Washington**

28 Incentive plans are evaluated on a case by case basis. Incentives tied to
operational efficiency or other measures which benefit ratepayers are allowed in

²⁸ In Docket No. EL 08-030 the settlement excluded bonuses related to "stockholder-benefitting financial goals." The settlement in Xcel rate case Docket No. EL09-009 removed payments based on financial performance indicators. In the settlement agreement signed July 7, 2010 in the Black Hills Power rate case Docket No. EL09-018 the *Staff Memorandum* states, "The settlement removes financial based incentive payments that were included in the capitalized labor costs for plant. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation."

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

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

³¹ The recent final order in Docket 09-035-23 follows this general policy as does the order in Docket 07-35-93. See also Missouri Corp. Rate Case Docket 97-035-01, pp. 10-12; US West Communications Rate Case Docket 95-049-05.

1 rates and incentives based on return on earnings or other measures that benefit
2 the shareholders are disallowed.³²

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

States that use another approach

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

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

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

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

27 No. Even though regulators generally disallow incentive compensation tied to financial
28 performance for ratemaking purposes, utilities continue to include financial performance
29 as a key component of their plans. In my opinion, utilities continue to tie incentive

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

1 payments to financial performance because by doing so they achieve the primary
2 objective of the incentive plans: to increase corporate earnings and, thereby, earnings per
3 share (EPS). However, since the utility retains the increased earnings these plans help
4 achieve, payments for the plans should be made from a portion of these increased
5 earnings. Thus, ratepayers need not subsidize properly designed incentive compensation
6 plans.

7
8 **Q: WHAT STATES USE A SHARING APPROACH FOR ANNUAL INCENTIVE**
9 **PLANS, SIMILAR TO THE 50/50 APPROACH YOU SUGGEST?**

10 **A:** Yes. Several states use a sharing approach to allocate the benefits derived from incentives
11 plans between shareholders and ratepayers, when incentive plans contain both financial and
12 operational measures. Some examples include:

13 **Arizona:** The commission follows the general rule that costs associated with
14 financial performance are excluded. In practice, this means that the costs of long-term plans
15 are excluded altogether and the costs of the short term annual cash plans are shared 50/50
16 between shareholders and ratepayers.³³

17 **Arkansas:** In the 2013 Entergy Arkansas rate case, the Arkansas commission
18 disallowed 50% of the Company's annual incentive plan because the plan had a funding
19 mechanism similar to the funding mechanism used by ONE Gas, where the amount paid for
20 incentives each year depends on how much money the utility makes that year.³⁴ In the 2015
21 Entergy rate case, the parties settled the case, but the Arkansas Commission rejected the

³³ See for example, APS 2008 rate case, Decision 70360, Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision 70011.

³⁴ Docket No. 13-028-U.

1 stipulation because it would have allowed more than 50% of the Company's incentive costs
2 in rates.

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

6 **Oklahoma:** In Oklahoma the Commission has consistently excluded 50% of annual
7 incentive plans, except for the two ONG rate cases mentioned earlier when the Commission
8 excluded 100% of the plans because of the ONEOK funding mechanism.³⁵

9 **Oregon:** Customer-based plans involving reliability, response speed, *etc.* are called
10 "merit" (operational) plans. Company-based plans which track increases to the bottom line,
11 ROE, *etc.* are called "performance" (financial) plans. 50% of the cost of merit plans is
12 disallowed and 75% of the performance plans is disallowed.

13
14 **Q: WHY IS THE DISTINCTION BETWEEN FINANCIAL PERFORMANCE**
15 **MEASURES AND OPERATIONAL MEASURES AN IMPORTANT**
16 **DISTINCTION FOR INCENTIVE COMPENSATION ANALYSIS?**

17 **A:** When incentive compensation payments are based on financial performance measures,
18 the compensation agreement between shareholders and employees could be loosely
19 stated in this manner: "if you will help increase shareholder earnings, we will pay you a
20 bonus." The intended beneficiaries to this agreement are the shareholders and the
21 employees. Ratepayers have no stake in this agreement; therefore, they should bear none
22 of the costs that result from such an agreement. If, instead, the agreement were stated in

1 this manner: “if you will help increase reliability and quality of service to the customers,
2 we will pay you a bonus,” then, ratepayers would have a stake in the agreement, and
3 could share in a portion of the costs. However, so long as some portion of the incentive
4 plan is designed to increase earnings, that portion of the plan should be funded out of the
5 increased earnings the plan helps produce.

6
7 **Q: ARE OG&E’s INCENTIVE PAYMENTS BASED ON FINANCIAL**
8 **PERFORMANCE MEASURES?**

9 A: Yes. A review of the Company’s incentive plan measures provided in the Company’s
10 response to AG 3-5, shows that Teamshare incentive payments are associated with the
11 following four categories:

- 12 ● Consolidated Earnings per Share
- 13 ● Utility Earnings per Share
- 14 ● Operating and Maintenance Expenses
- 15 ● Customer Satisfaction

16 A breakdown of the requested level of Teamshare expense between these categories was
17 provided in the Company’s response to AG 3-5 Supplement. This breakdown shows that
18 38.38% of the payout is related to customer satisfaction measures and 61.62% is related
19 to financial performance measures.

20
21 **Q: PLEASE ADDRESS THE ASSERTION THAT INCENTIVE PLANS SHOULD**
22 **BE INCLUDED IN RATES BECAUSE THEY ARE PART OF A TOTAL**
23 **COMPENSATION PACKAGE THAT IS COMPARABLE WITH THE**

³⁵ See e.g., AEP-PSO Cause Nos. PUD 06-285 and PUD 08-144; OG&E Cause No. PUD 05-151; and

1 **COMPENSATION PAID BY OTHER UTILITIES AND ARE NEEDED TO**
2 **ATTRACT AND RETAIN QUALIFIED PERSONNEL?**

3 A: In my experience, this is the argument typically raised by utilities seeking to justify
4 inclusion of incentive pay in rates. The argument, however, is problematic. First, it
5 misses the point. The question for regulators is not about what the company should pay;
6 the question is about what ratepayers should pay. The utility is free to offer whatever
7 compensation package it wants to offer, but most commissions agree that ratepayers
8 should not pay the costs of plans designed to increase corporate earnings. Also, as stated
9 above, because incentive pay related to financial performance is generally disallowed,
10 most of the utilities that OG&E competes with for talent generally do not recover all of
11 their incentive compensation in rates. Therefore, OG&E is not put at a competitive
12 disadvantage when its incentive pay is similarly adjusted.

13 The other common problem with the Company's "total compensation package"
14 argument is that when an incentive payment is based on achieving financial performance
15 goals there should be a financial benefit to the company that comes from achieving these
16 goals. This financial benefit should provide ample additional funds from which to make
17 the incentive payments. If not, the plan was poorly conceived. Thus, a utility is not
18 placed at a competitive disadvantage when incentive payments tied to financial
19 performance are not collected through rates, because the funding for these payments
20 should come out of the additional earnings the incentive plans help achieve.

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

3 A: I am recommending a 50/50 sharing of these costs between shareholders and ratepayers.
4 This recommendation is based on the recognition that more than 50% of the Company's
5 incentive compensation plan goals are related to financial performance measures, while a
6 smaller percentage relates to customer satisfaction and reliability. Because ratepayers
7 receive at least some benefit from these customer-related goals, some portion of the plan
8 costs could be allowed.

9
10 **Q: HAS THIS COMMISSION ADDRESSED RECOVERY OF INCENTIVE**
11 **COMPENSATION PAYMENTS IN PAST ORDERS?**

12 A: Yes. In its order in PUD 91-1190, at page 145, this Commission addressed ONG's
13 Gainshare Plan and the Executive Stock Performance Plan and disallowed the entire cost
14 of both plans, finding that the incentive plans were designed to increase corporate
15 earnings. In PUD 04-610, the ALJ recommended, and the Commission ordered, the
16 disallowance of the entire cost of ONG's incentive compensation payments. The ALJ
17 made the following recommendation:

18 The ALJ finds that incentive compensation should be disallowed from
19 inclusion in the rates paid by Oklahoma Natural's ratepayers. Incentive
20 compensation is typically tied to the attainment of certain financial goals,
21 efficiencies in operations or similar criteria, which create additional
22 income to the company, cost savings or other financial benefit. The ALJ
23 concurs with the argument of the Staff and AG that a well-designed
24 incentive compensation plan will generate resources from which to pay
25 the incentives to the employees. Therefore, the ALJ recommends
26 adoption of the Staff's recommended disallowance in the amount of
27 \$2,671,985.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

In PSO's 2006 rate case, PUD 200600285, the Commission disallowed 50% of AEP/PSO's annual incentive expense.³⁶

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

In PSO's 2008 rate case, PUD 200800144, the Commission again disallowed 50% of AEP/PSO's annual incentive plan.³⁷

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

In OG&E's 2005 rate case, PUD 200500151, the Commission's final order disallowed 60% of the Teamshare expense.

Incentive Compensation. OG&E presents \$9,308,619 in expense for incentive compensation under the "TeamShare" plan. The Referee does not accept the full amount as proposed by the company but reduces the expense by \$5,582,192.

Q: DO OTHER STATES' REGULATORY COMMISSIONS FOLLOW A 50/50 SHARING APPROACH FOR ANNUAL INCENTIVES?

A: Yes. As an example, regulators in Arkansas, Arizona, California and Oregon follow a general policy that does not attempt to assign a precise division of benefits between

³⁶ See Final Order in Cause No. PUD 200600285.
³⁷ See Final Order in Cause No. PUD 200800144.

1 shareholder and ratepayers but instead find that because these plans benefit both groups
2 the costs should be shared equally between them. In Arizona, the 50/50 approach is
3 consistently followed. As examples, see APS 2008 rate case, Decision 70360,
4 Southwest Gas 2008 rate case, Decision 70665 and UNS Gas 2008 rate case, Decision
5 70011.

6

7 **Q: HOW IS THE OIEC/OER ADJUSTMENT CALCULATED?**

8 A: OIEC/OER's adjustment is set forth below and can be seen at *Exhibit MG 2.5*.

9	Annual Incentive Plan Payments in Pro Forma Expense	\$15,427,914
10	Incentive Sharing Percentage	50%
11	Oklahoma Jurisdictional Percentage	<u>92.10 %</u>
12	OIEC/OER Adjustment to Annual Incentive Plans	<u>\$ 7,104,554</u>
13	Payroll Tax Expense Percentage	7.02%
14	OIEC/OER Adjustment Incentive Plan --Payroll Taxes	<u>\$ 498,740</u>

V. C. LONG-TERM STOCK INCENTIVE PLAN ADJUSTMENT

15 **Q: WHAT HAS OG&E PROPOSED WITH RESPECT TO THE RECOVERY OF**
16 **LONG-TERM STOCK-BASED INCENTIVES?**

17 A: The Company is proposing to include \$5,977,907³⁸ in rates for its long-term stock-based
18 incentive plans.

19

20 **Q: WHAT TYPES OF LONG-TERM INCENTIVES ARE PROVIDED TO**
21 **EXECUTIVES AT OG&E?**

³⁸ See *Exhibit MG 2.5*.

1 A: The Company provides a stock-based incentive plan to the officers, directors and
2 selected senior management of the Company. Officers and employees who contribute to
3 the management, growth and profitability of the Company are eligible for awards under
4 the plan.

5
6 **Q: DO YOU RECOMMEND THE INCLUSION OF THE LONG-TERM**
7 **INCENTIVE EXPENSE IN RATES?**

8 A: No. Incentive compensation payments to officers, executives and key employees of a
9 utility are generally excluded for ratemaking purposes, and I agree with this treatment.
10 Since officers of any corporation have a duty of loyalty to the corporation itself and not
11 to the customers of the company, these individuals typically put the interests of the
12 company first. Undoubtedly, the interests of the company and the interests of the
13 customer are not always the same, and at times, can be quite divergent. This natural
14 divergence of interests creates a situation where not every cost associated with executive
15 compensation is presumed to be a necessary cost of providing utility service. Many
16 regulators are inclined to exclude executive bonuses, incentive compensation and
17 supplemental benefits from utility rates, understanding that these costs would be better
18 borne by the utility shareholders.

19 It has been my experience that some utilities treat long-term executive incentive
20 compensation costs as a below-the-line item even without a Commission order directing
21 them to do so. Further, long-term executive incentive plans are specifically designed to
22 tie executive compensation to the financial performance of the company. This is done to

1 further align the interest of the employee with those of the shareholder. Since the
2 compensation of the employee is tied over a long period of time to the company's stock
3 price, it motivates employees to make business decisions from the perspective of long-
4 term shareholders. This intentional alignment of employee and shareholder interests
5 means the costs of these plans should be borne solely by the shareholders. It would be
6 inappropriate to require ratepayers to bear the costs of incentive plans designed to
7 encourage employees to put the interests of the shareholders first.

8
9 **Q: HOW IS LONG-TERM INCENTIVE COMPENSATION TREATED IN OTHER**
10 **STATES?**

11 A: The results of the Garrett Group Incentive Survey, discussed in the previous section of
12 this testimony, show that most states follow the general rule that incentive pay associated
13 with financial performance is not allowed in rates. This means that long-term, stock-
14 based incentives are not allowed in most states. In the synopsis of the incentive survey
15 results from each state that was included in the prior section of this testimony, the
16 treatment of long-term stock-based incentives in each state was underlined. According
17 to the survey, 20 of the 24 western states tend to exclude all or virtually all long-term
18 stock-based incentive pay, either through an outright ban on stock-based incentives or
19 through applying the *financial performance* rule, which has the effect of excluding long-
20 term earnings-based and stock-based awards. These states include Arizona, Arkansas,
21 California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada,
22 New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah,

1 Washington and Wyoming. In the other four states, Alaska, Iowa, Montana and
2 Nebraska, the issue just has not been addressed.

3
4 **Q: HAS THIS COMMISSION ADDRESSED EXECUTIVE INCENTIVE**
5 **COMPENSATION PLANS IN PAST ORDERS?**

6 A: Yes. On a number of occasions this Commission has addressed the issue of whether to
7 include incentive compensation in rates. On all occasions the Commission excluded the
8 entire amount of incentive payments made during the test year. For example, in its order
9 in Cause No. PUD 91-1190, at page 145, this Commission addressed ONG's employee
10 incentive plans, the Gainshare Plan and the Executive Stock Performance Plan. The
11 Commission disallowed the entire cost of both plans, which at that time was \$2,025,857,
12 based upon the arguments of Staff and the Attorney General that the plans were designed
13 to increase corporate earnings. In Cause No. PUD 04-610, after a hearing on the merits,
14 the ALJ recommended disallowance of the entire cost of both the executive and non-
15 executive payments and the Commission accepted that recommendation. With respect
16 to the executive incentive compensation the ALJ's recommendation states:

17 The ALJ finds that Executive Compensation typically includes a
18 component that is based upon certain goals of the company being
19 achieved. As with the incentive compensation addressed above,
20 the ALJ finds that an appropriately designed executive incentive
21 compensation will generate revenues or cost savings equivalent to
22 the compensation paid. Therefore, the ALJ finds that incentive
23 compensation provides a benefit to the shareholders rather than to
24 the ratepayers. It is therefore the recommendation of the ALJ that
25 the Executive Compensation incentives adjustment proposed by
26 Staff be adopted.

1 In PSO's 2006 rate case, PUD 200600285, the Commission disallowed 100% of the
2 utility's long-term incentive plan.

3 s. Long-Term Executive Stock Incentive Plan. The Commission
4 adopts Staff and OIEC's proposal to remove \$1,268,591 from PSO's cost-
5 of-service. This amount is reflected on HE-17 at page 16 of 24, OIEC
6 Adjustment No. H-5. The Commission finds that the FICA tax expense
7 associated with the long term executive stock incentive payments should
8 be removed for ratemaking purposes in the amount of \$225,567, as
9 proposed by OIEC. PSO's long-term executive incentive plan is
10 specifically designed to tie executive compensation to the financial
11 performance of AEP. It would be inappropriate to require ratepayers to
12 bear the costs of incentive plans designed to encourage employees to put
13 the interest of the shareholders first. Further, a well-designed incentive
14 plan should pay for itself. Thus, there is no need to include in rates
15 amounts that will be provided through higher earnings.³⁹

16 In PSO's 2008 rate case, PUD 200800144, the Commission again disallowed 100% of
17 the utility's long-term incentive costs.

18 With regard to long term incentive compensation, the Commission finds
19 that the recommendation of the AG, OIEC and Staff to disallow 100% of
20 long term incentive compensation is reasonable and should be adopted by
21 the Commission. The performance measures that result in the payment of
22 long term incentive compensation are financial goals that benefit
23 shareholders, rather than ratepayers.⁴⁰

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

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

³⁹ See Final Order in Cause No. PUD 200600285 at page 145.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

Q: IS THIS ARGUMENT PLAUSIBLE?

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

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

⁴⁰ Order No. 564437 in Cause No. PUD 200800144 at page 21.

1 Therefore the Commission accepts BCP's and SNHG's
2 recommendations to disallow recovery of expenses associated with
3 LTIP. Both parties provide a valid argument that this type of
4 incentive plan is mainly for the benefit of shareholders. Further,
5 both BCP and SNHG provide examples of numerous other
6 jurisdictions that do not allow the recovery of these costs and,
7 therefore, disallowance in this instance would not place NPC in a
8 competitive disadvantage.⁴¹ (Emphasis added).

9 **Q: WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE**
10 **COMPANY'S RECOVERY OF STOCK INCENTIVE COMPENSATION?**

11 A: For the reasons outlined above, and based upon prior Commission orders, I am
12 recommending that 100% of the Company's stock incentive expense be excluded for
13 ratemaking purposes. This adjustment is set forth below and at *Exhibit MG 2.5*.

14	Adjustment to Exclude 100% of the Stock Incentive Plan	\$5,977,907
15	Oklahoma Jurisdictional Allocation Percentage	<u>92.1%</u>
16	Oklahoma Jurisdictional Adjustment to Stock Incentive Plan	<u>\$5,505,652</u>

V. D. NON-QUALIFIED SUPPLEMENTAL EMPLOYEE RETIREMENT PLANS

17 **Q: PLEASE DESCRIBE THE SUPPLEMENTAL EMPLOYEE PENSION PLAN.**

18 A: The Company provides supplemental retirement plan benefits to certain highly-
19 compensated individuals at the Company. These supplemental retirement plans for highly
20 compensated individuals are provided because benefits under the general retirement plans
21 are subject to limitations under the Internal Revenue Code. Benefits payable under these
22 supplemental plans are typically equivalent to the amounts that would have been paid but
23 for the limitations imposed by the Code. In general, the limitations imposed by the Code
24 allow for the computation of benefits on annual compensation levels of up to \$260,000 for

⁴¹ See Final Order in Docket 08-12002 at paragraph 549.
Responsive Testimony of Mark E. Garrett
Cause No. PUD 201500273

1 2014 and \$265,000 for 2015. Retirement benefits on compensation levels in excess of
2 annual compensation limits are paid through supplemental plans. Thus, supplemental
3 retirement plans for highly compensated employees are designed to provide benefits in
4 addition to the benefits provided under the general pension plans of the company. These
5 plans are referred to as *non-qualified* plans because they do not qualify as a deductible tax
6 expense under the code.
7

8 **Q: WHAT AMOUNTS WERE INCLUDED IN PRO FORMA OPERATING EXPENSE**
9 **FOR THE SUPPLEMENTAL EMPLOYEE RETIREMENT PLANS?**

10 A: In the test year, the Company paid \$1,860,147 for non-qualified plans.
11

12 **Q: WHAT DO YOU RECOMMEND WITH RESPECT TO SUPPLEMENTAL**
13 **EXECUTIVE RETIREMENT COSTS?**

14 A: I recommend that SERP costs be disallowed as a matter of principle. If SERP costs are
15 disallowed, ratepayers will pay for all of the executive benefits included in the
16 Company's regular pension plans, and shareholders will pay for the additional executive
17 benefits included in the supplemental plan. For ratemaking purposes, shareholders
18 should bear the additional costs associated with supplemental benefits to highly
19 compensated executives, since these costs are not necessary for the provision of utility
20 service, but are instead discretionary costs of the shareholders designed to attract, retain
21 and reward highly compensated employees. Further, because officers of any corporation
22 have a duty of loyalty to the corporation, these individuals are required to put the interest

1 of the company first. This creates a situation where not every cost associated with
2 executive compensation is presumed to be a cost appropriately passed on to ratepayers.
3 Many regulators are inclined to exclude executive bonuses, incentive compensation and
4 supplemental benefits from utility rates, understanding that these costs would be better
5 borne by the utility shareholders.

6
7 **Q: HOW HAS SERP EXPENSE BEEN TREATED IN OTHER JURISDICTIONS**
8 **WHERE YOU HAVE TESTIFIED ON THE ISSUE?**

9 A: As summarized below, SERP expenses have been disallowed as follows:

10 In Texas, in Entergy's rate case, Docket No. 39896, the Texas PUC disallowed
11 all of the Company's SERP costs.

12 140. ETI provides non-qualified supplemental executive
13 retirement plans for highly compensated individuals such as key
14 managerial employees and executives that, because of limitations
15 imposed under the Internal Revenue Code, would otherwise not
16 receive retirement benefits on their annual compensation over
17 \$245,000 per year.

18
19 141. ETI's non-qualified supplemental executive retirement
20 plans are discretionary costs designed to attract, retain, and reward
21 highly compensated employees whose interests are more closely
22 aligned with those of the shareholders than the customers.

23
24 142. ETI's non-qualified executive retirement benefits in the
25 amount of \$2,114,931 are not reasonable or necessary to provide
26 utility service to the public, not in the public interest, and should
27 not be included in ETI's cost of service.

28 In Oklahoma, the Commission disallowed 100% of AEP/PSO's SERP expense in
29 PSO's 2006 rate case, Cause No. PUD 200600285. Specifically, the Commission stated:

1 q. **Employee Benefits-Supplemental Executive Retirement**
2 **Plan (“SERP”).**
3

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

12 Again, in PSO’s 2008 rate case, Cause No. PUD 200800144, the Commission disallowed
13 100% of the Company’s SERP expense.

14 **11. Supplemental Executive Retirement Plan (“SERP”).**
15

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

31 In Nevada, the Commission disallowed SERP expense in Docket Nos. 01-10001,
32 03-10001, 06-11022, 08-12002, and 11-06006.

33 In Arkansas, the Commission disallowed SERP expense in Entergy Arkansas’s
34 last litigated rate case in that state, Docket No. 13-028-U. The Commission agreed with
35 my testimony that shareholders, not ratepayers, should pay for the cost of Entergy

1 Arkansas' Supplemental Executive Retirement Plans. In Commission Order No. 21 in
2 that Docket, the Arkansas Commission determined that SERP expenses are not
3 necessary to provide utility service, but rather are discretionary costs implemented by
4 Entergy Arkansas that should be disallowed.

5

6 **Q: HOW IS SERP TREATED IN OTHER STATES?**

7 A: It is my understanding that SERP is also disallowed in the states of Oregon,⁴² Idaho⁴³
8 and Arizona.⁴⁴

9

10 **Q: WHAT IS THE IMPACT OF YOUR ADJUSTMENT?**

11 A: The impact of this adjustment is set forth below, and shown at *Exhibit MG 2.6*.

12	Adjustment to Remove Supplemental Retirement Plan Expense	(\$1,860,567)
13	Oklahoma Jurisdictional Allocation Percentage	<u>92.10%</u>
14	Oklahoma Jurisdictional Adjustment	<u>(\$1,713,195)</u>

⁴² See Oregon Public Utilities Commission, Order No. 01-787, September 7, 2001, page 44.

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

⁴³ See Idaho Public Utilities Commission Order No. 32196 issued February 28, 2011 in Rocky Mountain Power’s rate case, Case No. Pac-E-10-07:

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

⁴⁴ The Arizona Corporation Commission has issued several decisions in which it denied rate recovery for SERP expenses. See 258 PUR 4th 353 (2007) Re Arizona Public Service Company, 247 PUR 4th 243 (2006), In Re Southwest Gas Corp., 2008 WL 2332953 (Ariz Corp Comm Decision 70360, May 27, 2008), In the Matter of the Application of UNS Electric, and 2007 WL 4731250 (Ariz Corp Comm Decision 70011, November 27, 2007) Re UNS Gas, Inc.

V. E. AD VALOREM TAX EXPENSE ADJUSTMENT

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

3 A: The Company is proposing to increase test year ad valorem tax expense by the average
4 percentage increase experienced in this account over the past 3-year period.

5
6 **Q: DO YOU AGREE WITH THE COMPANY'S APPROACH?**

7 A: No. The Company's approach is not an appropriate method for quantifying a *known and*
8 *measurable change* to ad valorem tax. Since ad valorem tax expense each year is the
9 result of extensive negotiations with the Oklahoma Tax Commission regarding the
10 valuation of OG&E's taxable property, the amount cannot be estimated based on average
11 annual increases in the expense level over the past several years. In other words, there is
12 no relationship between the amount of ad valorem tax paid in the past and the amount of
13 tax expense that will be assessed during the rate-effective period. The expense increase
14 for the rate-effective period, if any, cannot be predicted as proposed by the Company.

15
16 **Q: WHAT ADJUSTMENT DO YOU RECOMMEND?**

17 A: Since the Company's proposed adjustment for ad valorem tax expense is based on a
18 flawed methodology, I recommend the Commission reject the adjustment as shown
19 below and set forth at *Exhibit MG 2.8*.

20 **Adjustment to Reverse OG&E's Ad Valorem Tax Adjustment (\$4,166,889)**

V. F. VEGETATION MANAGEMENT COST INCREASE

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

3 A: OG&E is proposing significant increases for both distribution and transmission
4 vegetation management costs. OG&E is proposing increases over test year levels of
5 \$11,518,525 for distribution costs, and \$1,692,500 for transmission costs,⁴⁵ which is an
6 81% increase for distribution costs and a 60% increase for transmission costs.⁴⁶

7
8 **Q: DOES OG&E PROVIDE ADEQUATE SUPPORT FOR THESE INCREASES?**

9 A: No. For the transmission increase, OG&E provides no support at all. It merely asserts
10 that there has been a 15% increase in line-miles since 2010, which in no way explains a
11 60% cost increase over test year levels.⁴⁷ For the distribution increase, OG&E points to
12 the expiration of the system hardening rider—which provided the Company recovery of
13 additional vegetation management costs from 2010 through 2014 (on top of what OG&E
14 collected in base rates) for vegetation management to help OG&E catch up to its 4-year
15 cycle requirements. OG&E asserts that going forward it needs a level of costs similar to
16 the level provided through the system hardening rider to once again help it catch up with
17 its 4-year cycle requirements.

18

⁴⁵ See W/P H 2.43 and W/P H 2.45.

⁴⁶ Test year levels were: \$14,272,378 for distribution and \$2,842,153 for transmission.

⁴⁷ See Direct Testimony of Jarod Cassada at page 7.

1 **Q: WHY HAS OG&E ONCE AGAIN FALLEN BEHIND ON ITS 4-YEAR CYCLE**
2 **REQUIREMENTS?**

3 A: Over the past several years as the system hardening rider revenues declined, OG&E
4 failed to increase the amount it was spending out of base rates to keep up with the 4-year
5 cycle program. For a visual depiction, the chart provided in Mr. Cassada testimony at
6 page 14 clearly shows that while system hardening expenditures were declining from
7 2010 through 2014, OG&E's base rate expenditures were not increasing. This fact is
8 very important in light of OG&E's response to AG Data Request 7-18, where OG&E
9 made the following important admission:

10 With the expiration of system hardening, OG&E no longer has the
11 resources to maintain all lines the same and moved to a 2-tier cycle
12 program which categorized circuits in two ways: Circuits with high
13 customer density and/or a high priority for restoration are categorized as
14 category 1 and are maintained end-to-end including preventive brush
15 control and pole clearing. Category 2 circuits are inspected on cycle and
16 only vegetation interfering with reliability is addressed. . . . It is OG&E's
17 intent to eliminate the 2-tier cycle and clear all circuits the same.

18 This response actually includes three important admissions: (1) that OG&E chose not to
19 replace the declining system hardening revenues with additional OG&E expenditures out
20 of base rates; (2) that OG&E changed its cycle program to a 2-tiered approach that did
21 not adequately clear the second-tier lines; and (3) that OG&E now wants to return to a
22 program that clears all lines the same. To return to a program that clears all lines the
23 same, OG&E asserts that it will have to once again spend additional funds to "catch up"
24 the cost of clearing the second-tier lines that were inadequately cleared under its elective
25 2-tier cycle program.

1 **Q: WAS IT APPROPRIATE FOR OG&E TO FORGO MAKING THE**
2 **ADDITIONAL EXPENDITURES OVER THE PAST SEVERAL YEARS IF**
3 **THOSE EXPENDITURES WERE NEEDED TO ADEQUATELY MAINTAIN**
4 **THE SYSTEM?**

5 A: No. OG&E is obligated to adequately maintain its system. It cannot simply choose to
6 forgo making necessary maintenance expenditures and keep those funds to improve its
7 bottom line. In other words, OG&E cannot choose to forgo necessary maintenance
8 expenditures in order to send more money to the shareholders – and then ask ratepayers
9 to help “catch up” the foregone maintenance costs.

10

11 **Q: WHAT SHOULD OG&E BE REQUIRED TO DO AT THIS POINT?**

12 A: At this point, OG&E should quantify the “catch up” amount – that is, the amount OG&E
13 determines it should have spent over the last several years to maintain an adequate
14 vegetation management program rather than adopting a 2-tiered approach in which the
15 second-tier lines were not adequately cleared. OG&E should then pay this “catch-up”
16 amount out of the Company’s retained earnings to promptly clear the second-tier lines
17 that were not adequately cleared rather than recover such amount from ratepayers.

18

19 **Q: WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?**

20 A: In my opinion, the Commission should hold OG&E accountable for failing to make the
21 necessary expenditures required to adequately maintain its vegetation management

1 program over the past several years by setting the vegetation management expense at the
2 5-year average spending level.

3

4 **Q: ARE YOU RECOMMENDING AN ADJUSTMENT AT THIS TIME?**

5 A: Yes. For now, I recommend that the 5-year average spending level of \$21.5 million be
6 used to set the expense level for distribution vegetation management costs. For the
7 transmission system, I recommend that the test year level be used for setting rates
8 because the Company provided no credible support for its requested increase. However,
9 I reserve the right to update these recommendations based on the responsive testimony
10 filed by other witnesses and the rebuttal testimony filed by OG&E.

11

12 **Q: WHAT ARE THE ADJUSTMENTS?**

13 A: The adjustments for distribution and transmission vegetation management costs are set
14 forth below and can be seen in more detail at *Exhibit MG 2.13*.

OIEC/OER Adjustment to Vegetation Management Expense	
Description	Okla Juris Amt
Adjust Distribution Expense to the 5-Year Average Spend Level	\$(4,290,903)
Adjust Transmission Expense to the Test-Year Level	\$(1,692,501)
OIEC/OER Adjustment for Vegetation Management Expense	\$(5,983,404)

V. G. CORPORATE COST ALLOCATION INCREASE

1 **Q: WHAT IS OG&E PROPOSING WITH RESPECT TO ITS CORPORATE COST**
2 **ALLOCATIONS FROM THE HOLDING COMPANY?**

3 A: OG&E is proposing to increase rates by \$6,057,685 for costs the Holding Company will
4 no longer be able to allocate to Enable Midstream Partners starting in 2016. These costs
5 include costs for central functions such as Accounting, Human Resources and Information
6 Technology. Mr. Thenmadathil describes the adjustment at page 10 of his Direct
7 Testimony:

8 This adjustment increases O&M to account for certain expenses that will
9 no longer be allocated to affiliates. The joint venture between OG&E
10 affiliate Enogex and CenterPoint Energy formed a standalone company
11 named Enable Midstream Partners. This company will no longer share
12 costs with OG&E as it has in the past. Sharing of certain costs with the
13 affiliate company will cease by the end of the pro forma period causing
14 expense levels for OG&E to increase without the benefit of an affiliate to
15 share costs with.

16 This description gives the impression that these costs are OG&E's costs that it shares
17 with Enable. That, however, is not quite right. Actually, these costs are OGE Energy
18 Corporation Holding Company costs that are now being allocated to both OG&E and
19 Enable. Beginning in 2016, OGE Energy Corporation will no longer be allocating these
20 costs to Enable. So, going forward it plans to allocate all of the costs to OG&E instead.

21

22 **Q: DO YOU AGREE WITH THIS ADJUSTMENT?**

23 A: No, for several reasons. First, the cost allocation change is outside the test year and
24 outside the 6-month post-test year period. OGE Energy Corporation's cost-sharing
25 agreement with Enable ends in January 2016, which is beyond the 6-month post-test year

1 cutoff date. Title 17 Sec. 284 requires that the Commission give effect to known and
2 measurable changes that occur during the 6-month period after test year. According to
3 the statute, the *change* must occur *during* the 6-month period. This change occurs
4 beyond the 6-month period. Second, for recovery in rates, costs must be both necessary
5 and reasonable – necessary for the provision of service and reasonable in amount. The
6 costs that OGE Energy Corporation wants to allocate to OG&E in 2016 may be
7 necessary for the holding company, but the amount is not a reasonable amount for
8 OG&E. The reasonable amount of these costs allocable to OG&E is the amount the
9 Company was paying when some the costs were being allocated to Enable. Now that
10 Enable is no longer obligated to pay its share of these costs, OGE Energy Corporation
11 cannot simply slough off the excess costs onto OG&E and expect ratepayers to pay the
12 higher levels. Third, if these costs are included in rates and OGE Energy is able to
13 reduce or eliminate these costs, then OGE Energy Corporation will reap a windfall from
14 this adjustment. The bottom line is that these costs must be recouped by OGE Energy
15 Corporation, the parent company, not OG&E, the utility.

16
17 **Q: WHAT ADJUSTMENT ARE YOU PROPOSING?**

18 A: I am proposing to reverse OG&E's proposed adjustment to increase rates for costs the
19 parent company will no longer be able to allocate to Enable Midstream Partners starting
20 in January 2016. The adjustment reduces pro forma operating expense by \$6,057,685,
21 which is \$5,579,128 to the Oklahoma jurisdiction, as shown at *Exhibit MG 2.7*.

22 **Adjustment to Reverse OG&E's Affiliate Expense Adjustment (\$5,579,128)**

Adjustment to Remove Affiliate Expenses

VI. DEPRECIATION AND AMORTIZATION EXPENSE ADJUSTMENTS

1 **VI. A. ADJUSTMENT TO APPLY OIEC/OER RATES TO 6-MONTH PLANT**

2 **Q: WHAT IS THE ISSUE WITH DEPRECIATION EXPENSE?**

3 A: OIEC/OER witness Mr. Jacob Pous proposes numerous changes to the Company's
4 depreciation study resulting in new proposed depreciation rates for many of the
5 Company's plant accounts. I applied these recommended depreciation rates to OG&E's
6 plant balances at December 31, 2015, the 6-month cut off in this case. The impact of
7 this adjustment is set forth below. The calculations can be seen at *Exhibit MG 2.10*.

OIEC/OER Adjustment to Depreciation Expense	
Description	Adjustment
Depreciation Expense Adjustment	\$41,014,841
Oklahoma Juris Allocator	90.94%
Total Adjustment	\$37,298,897

VI. B. STRANDED SMART-METER COSTS

8 **Q: WHAT IS THE ISSUE WITH RESPECT TO THE STRANDED SMART METER**
9 **COSTS?**

10 A: Pursuant to the Stipulation reached among the parties and approved by the Commission
11 in Cause No. PUD 201000029, OG&E accumulated costs associated with the stranded
12 meters and the Smart Grid Web Portal in a regulatory asset account. The test year
13 balance for both items is \$34,329,676 and \$6,127,104, respectively. OG&E now seeks
14 to include these costs in rate base and recover the costs from ratepayers through a 6-year

1 amortization in the amounts \$5,721,613 for stranded meters and \$1,021,184 for the web
2 portal.

3
4 **Q: DO YOU AGREE WITH THE COMPANY'S PROPOSED TREATMENT?**

5 A: No. While the six year amortization was an agreed-to provision in the Stipulation
6 approved in Cause No. PUD 201000029, that provision was part of an overall Stipulation
7 that included OG&E's agreement to file a rate case in 2013. The amortization provision
8 contemplated an amortization of costs beginning with issuance of a 2013 OG&E rate
9 case order. OG&E failed to file a 2013 rate case as required by the Stipulation and later
10 refused to file the case even when requested by Staff to do so. As a consequence,
11 OG&E's failure to file a 2013 rate case should result in the Company's forfeiture of any
12 benefits that would have been derived from its promised 2013 rate case. One of these
13 benefits would have been the six year amortization of stranded costs resulting from the
14 Smart Grid roll-out.

15
16 **Q: WHAT DO YOU PROPOSE INSTEAD?**

17 A: I propose that the stranded costs be amortized over the 15-year life of the new smart
18 meters. This is the approach taken by PSO for its stranded meter costs and I believe it is
19 the correct amortization period absent an agreement by the parties to a shorter period.

20
21 **Q: WHAT IS THE IMPACT OF THIS ADJUSTMENT?**

22 A: The impact is set forth below, and at *Exhibit MG 2.12*.

Adjustment to Amortize Stranded Smart Grid Costs over 15-Years			
Description	6-Year	15-Year	Adjustment
Total Annual Amortization	\$6,742,797	\$2,697,119	\$4,045,678
Oklahoma Juris Allocator			90.94%
Total Adjustment			\$3,679,140

VII. ADJUSTMENTS PROPOSED BY OTHER OIEC/OER WITNESSES

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

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

4 **Recommendations of Mr. David Parcell**

5 Mr. Parcell addresses the cost of capital issues. Specifically he recommends a
6 Return on Equity (“ROE”) of 9.0%. The impact of his recommended ROE on the
7 Oklahoma revenue requirement is a reduction of **\$(45,476,468)**.

8 **Recommendations of Mr. Jacob Pous**

9 Mr. Pous proposes new depreciation rates for several OG&E plant accounts. His
10 recommendations result in a decrease in Oklahoma depreciation expense of
11 **\$(40,978,036)**.

VIII. CONCLUSION

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

2 A: Yes. My testimony does not address every potential issue. The fact that I do not express
3 an opinion on a particular issue is not to be interpreted as agreement with the Company's
4 position on that issue.

5

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

7 A: Yes, it does.

MARK E. GARRETT

CONTACT INFORMATION:

50 Penn Place, Suite 410
1900 NW Expressway
Oklahoma City, OK 73118
(405) 239-2226

EDUCATION:

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

CREDENTIALS:

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

WORK HISTORY:

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

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

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

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

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

1. **Texas Gas Service, 2016 (Docket No. 10488)** – Participating as an expert witness on behalf of South Jefferson County Service Area (“SJCSA”) before the Texas Railroad Commission in TGS’s General Rate Case application, sponsoring testimony to address the utility’s overall revenue requirement and various rate design proposals.
2. **Oklahoma Gas and Electric Company, 2016 (Cause No. PUD 201500273)** – Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in OG&E’s General Rate Case application. Sponsoring testimony to address the utility’s overall revenue requirement and rate design proposals.
3. **Anchorage Municipal Light and Power, 2016 (Docket No. U-13-097)** – Participating as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on rates and tariffs proposed for customer-owned combined heat and power plant generation.
4. **Oklahoma Natural Gas Company, 2015 (Cause No. PUD 201500213)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG’s General Rate Case application. Sponsored testimony to address the utility’s overall revenue requirement and rate design proposals.
5. **Oklahoma Gas & Electric Company, 2015 (Cause No. PUD 201500274)** – Participated as an expert witness on behalf of The Alliance for Solar Choice (“TASC”) before the Oklahoma Corporation Commission to address OG&E’s proposed Distributed Generation (“DG”) rates for solar DG customers.
6. **Nevada Power Company, 2015 (Docket No. 15-07004)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”)¹ before the Nevada PUC. Sponsoring written and oral testimony in NPC’s 2015 Integrated Resource Plan to provide analysis of the On Line transmission line allocation, the Siverhawk plant acquisition, and the Griffith contract termination.
7. **Oklahoma Gas & Electric Company, 2015 (Docket No. 15-034-U)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”)² before the Arkansas Public Service Commission in OG&E’s Act 310 application to implement a rider to recover environmental compliance costs.
8. **MGM Resorts, LLC, 2015 (Docket No. 15-05017)** – Participating as an expert witness on behalf of the MGM Resorts, LLC before the Nevada PUC. Sponsoring written and oral testimony in MGM’s application to purchase energy and capacity from a provider other than Nevada Power.
9. **Entergy Arkansas, 2015 (Docket No. 15-015-U)** – Participating as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”) an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy’s general rate case to provide testimony on various revenue requirement issues.
10. **Public Service Company of Oklahoma, 2015 (Cause No. PUD 201500208)** – Participating as an

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

² ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

- expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.
11. **Nevada Power Company, 2014 (Docket No. 14-05003)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored written and oral testimony in NPC environmental compliance case, called the Emissions Reduction and Capacity Replacement case. The main focus of our testimony was our recommendation to eliminate the \$438M Moapa solar project from the compliance plan.
 12. **Nevada Power Company, 2014 (Docket No. 14-05004)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsor written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
 13. **Oklahoma Gas and Electric Co., 2014 (Cause No. PUD 201400229)** – Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”)³ in OG&E's Environmental Compliance and Mustang Modernization Plan before the Oklahoma Corporation Commission to provide testimony addressing the economics and rate impacts of the plan.
 14. **Sourcegas Arkansas, Inc., 2014 (Docket No. 13-079-U)** Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”), an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in SGA's general rate case to provide testimony on various revenue requirement issues.
 15. **Anchorage Municipal Light and Power, 2014 (Docket No. U-13-184)** – Participating as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on various revenue requirement and cost of service issues.
 16. **Public Service Company of Oklahoma, 2014 (Cause No. PUD 201300217)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.
 17. **Entergy Texas Inc., 2013 (PUC Docket No. 41791)** – Participating as an expert witness on behalf of the Cities⁴ in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.
 18. **MidAmerican/NV Energy Merger, 2013 (Docket No. 13-07021)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored testimony to address various issues raised in the proposed acquisition of NV Energy by MidAmerican Energy Holdings Company, including capital structure and acquisition premium recovery issues.
 19. **Entergy Arkansas, 2013 (Docket No. 13-028-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”) an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

³ OIEC is an association of approximately 25 large commercial and industrial customers in Oklahoma.

⁴ The Cities include Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange.

20. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers⁵ before the Nevada PUC in SPPC’s general rate case proceeding to provide testimony on various cost of service and revenue requirement issues. Sponsored written and oral testimony in the depreciation phase, the revenue requirement phase and the rate design phase of these proceedings.
21. **Gulf Power Company, 2013 (Docket No. 130140-EI)** – Participated as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power’s general rate case proceeding to provide testimony on various revenue requirement issues.
22. **Public Service Company of Oklahoma, 2013 (Cause No. PUD 201200054)** – Participating as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission (“OCC”) to provide testimony in PSO’s application seeking Commission approval of its settlement agreement with EPA.
23. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s general rate case proceeding to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
24. **Doyon Utilities, 2012 Alaska Rate Case (Docket No. TA7-717)** – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.
25. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University’s general rate case with the Corix Group, which provides utility services to the University.
26. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility’s request to earn additional compensation on a 510MW purchased power agreement with Exelon
27. **Centerpoint Energy Texas Gas, 2012 (Docket No. GUD 10182)** – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.
28. **Entergy Texas Inc., 2012 (PUC Docket No. 39896)** – Participated as an expert witness on behalf of the Cities in ETI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
29. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participating as an expert witness on behalf of the OIEC before the OCC in ONG’s Performance Based Rate (“PBR”) application seeking Commission approval of a requested rate increase based upon formula results for 2011.
30. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility

⁵ The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

services to the university.

31. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participating as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.
32. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participated as an expert witness on behalf of Enbridge before the OCC in Empire’s rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
33. **Nevada Power Company, 2011, (Docket No. 11-04010)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored written and oral testimony to address proposed changes to the Company’s customer deposit rules.
34. **Nevada Power Company, 2011, (Docket No. 11-06006)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
35. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application seeking rider recovery of third party SPP transmission costs and fees.
36. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087)** – Participating as an expert witness on behalf of OIEC before the OCC in OG&E’s rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
37. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-109-U)** – Participated as an expert witness on behalf of Gerdau Macsteel before the Arkansas Public Service Commission in OG&E’s application to recover Smart Grid costs to make recommendations regarding the allocation of the Smart Grid costs.
38. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking to include retire medical expense in the Company’s pension tracker mechanism.
39. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of OIEC before the Oklahoma Corporation Commission in AEP/PSO’s application to recover ice storm O&M expenses through a regulatory asset/rider mechanism to address tax impact and return issues in the proposed rider.
40. **Public Service Company of Colorado, 2011 (Docket No. 10AL-908E)** – Participated as an expert witness on behalf of the Colorado Retail Council (“CRC”) before the Colorado Public Utilities Commission providing written and live testimony to address PSCo’s proposed Environmental Tariff.
41. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-067-U)** – Participated as an expert witness on behalf of the Northwest Arkansas Industrial Energy Consumers (“NWIEC”)⁶ before the

⁶ NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

42. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-146)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking rider recovery of third party SPP transmission costs and SPP administration fees.
43. **Massachusetts Electric Co. & Nantucket Electric Co. d/b/a National Grid, 2010 (Docket No. DPU 10-54)** – Participated as an expert witness providing both written and live testimony before the Massachusetts Department of Public Utilities on behalf of the Associated Industries of Massachusetts (“AIM”) to address the Company's proposed participation in the 438MW Cape Wind project in Nantucket Sound.
44. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of the OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.
45. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participating as an expert witness on behalf of the Alliance of Texas Municipalities (“ATM”) before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
46. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147)** – Participating as an expert witness on behalf of the Alliance of Xcel Municipalities (“AXM”) in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.
47. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participating as an expert witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E's 220MW self-build wind project.
48. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-29)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking pre-approval of deployment of smart-grid technology and rider-recovery of the associated costs. Sponsored written testimony to address smart-grid deployment and time-differentiated fuel rates.
49. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-01)** – Participated as an expert witness on behalf of the OIEC before the OCC in the Company's proposed Green Energy Choice Tariff. Sponsored testimony to address the pricing and ratemaking treatment of the Company's proposed wind subscription tariff.
50. **Nevada Power Company, 2010 (Docket No. 10-02009)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC to provide testimony in NPC's Internal Resource Plan to address the ratemaking treatment of the proposed ON Line transmission line.
51. **Entergy Texas Inc., 2010 (PUC Docket No. 37744)** – Participating as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.
52. **El Paso Electric Company, 2010 (PUC Docket No. 37690)** – Participated as an expert witness on

behalf of the City of El Paso in the EPI general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

53. **Public Service Company of Oklahoma, 2009 (Cause No. 09-196)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application for approval of DSM programs and cost recovery. Sponsored testimony to address program costs, lost revenue recovery, cost allocations and incentives.
54. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 09-230 and 09-231)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.
55. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case. Provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
56. **Nevada Power Company, 2009, (Docket No. 08-12002)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
57. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031)** – Participated as an expert witness on behalf of OIEC before the OCC in PSO's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.
58. **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.
59. **Rocky Mountain Power, 2009 (Docket No. 08-035-38)** – Participated as an expert witness on behalf of the Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.
60. **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.
61. **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.
62. **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.
63. **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.

64. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334)** – Participated as an expert witness on behalf of the Cities in EGSI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
65. **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.
66. **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.
67. **Rocky Mountain Power, 2008 (Docket No. 07-035-93)** – Participating as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp’s general rate case to provide testimony on various revenue requirement issues.
68. **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.
69. **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.
70. **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.
71. **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.
72. **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.
73. **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.
74. **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.

75. **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.
76. **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.
77. **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.
78. **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.
79. **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.
80. **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.
81. **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.
82. **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.
83. **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.
84. **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.
85. **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.

86. **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.
87. **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.
88. **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:
89. **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.
90. **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.
91. **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.
92. **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.
93. **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.
94. **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.
95. **McCarthy Family Farms, 2003** – Participated as a consultant to assist McCarthy Family Farms in converting a biomass and biosolids composting process into a renewable energy power producing business in California.

96. **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.
97. **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.
98. **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.
99. **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.
100. **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.
101. **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.
102. **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.
103. **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.
104. **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.
105. **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.

106. **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.
107. **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.
108. **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.
109. **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.
110. **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.
111. **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.
112. **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.
113. **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.
114. **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.

115. **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.
116. **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.
117. **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.
118. **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.
119. **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.
120. **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.
121. **Enogex, Inc., 1995 (FERC 95-10-000)** - Analyzed Enogex's application before the FERC to increase gas transportation rates for the Oklahoma Independent Petroleum Association and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.
122. **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.
123. **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.
124. **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.

- 125. 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.

- 126. 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.

OKLAHOMA GAS & ELECTRIC COMPANY
OIEC/OER WORKPAPERS - SUMMARY OF PROPOSED ADJUSTMENTS
 Test Year Ended 6-30-15
 Cause NO. PUD 201500273

Ln	Descriptions	Witness	Ref.	Rate Base Items	ROR W/Tax	Oklahoma Impact
1	OG&E Proposed Rate Increase					\$ 92,494,692
2	Rate Base Adjustments			\$ 4,152,329,406		
3	To Adjust Plant Investment to 6-Month Level	Garrett	MG2.1	12,473,690	11.548%	1,440,487
4	To Adjust Accumulated Depreciation to 6-Month Level	Garrett	MG2.1	28,840,304	11.548%	3,330,536
5	To Adjust Plant Held for Future Use	Garrett	MG2.1	(1,079,239)	11.548%	(124,633)
6	To Adjust ADFIT to 6-Month Level	Garrett	MG2.1	734,262	11.548%	84,794
7	To Adjust Customer Deposits to 6-Month Level	Garrett	MG2.1	(1,148,809)	11.548%	(132,667)
8	To Adjust AROs to 6-Month Level	Garrett	MG2.1	(3,490,626)	11.548%	(403,104)
9	To Adjust Materials and Supplies to 6-Month Level	Garrett	MG2.1	(799,431)	11.548%	(92,320)
10	To Adjust Prepayments to 6-Month Level	Garrett	MG2.1	79,454	11.548%	9,175
11	To Adjust Gain on Sale (Acct 254) to 6-Month Level	Garrett	MG2.1	(944,309)	11.548%	(109,051)
12	To Adjust Net Pension Asset Balance to 6-Month Level	Garrett	MG2.2	(6,447,432)	11.548%	(744,562)
13	Total Rate Base Adjustments			<u>\$ 28,217,864</u>		<u>\$ 3,258,655</u>
14	Cost of Capital					
15	To Apply OIEC/OER Cost of Capital Adjustments	Parcell	MG2.14	\$ 4,180,547,270	-1.088%	\$ (45,476,468)
16	Revenue and Expense Adjustments			ROE	Equity %	
				9.000%	53.3%	
17	To Adjust Customer Growth to 6-Month Cutoff	Garrett	MG2.9			(5,375,062)
18	To Recognize Gain on Sale of Utility Assets	Garrett	MG2.11			(591,808)
19	To Reverse OG&E Payroll Adjustment	Garrett	MG2.4			(5,097,319)
20	To Adjust Payroll Taxes for Proposed Payroll Adjustments	Garrett	MG2.4			(357,881)
21	To Remove 50% of Annual Incentive Plan	Garrett	MG2.5			(7,104,554)
22	To Remove 50% of Payroll Tax on Annual Incentive Plan	Garrett	MG2.5			(498,740)
23	To Remove 100% of Executive Incentive Plan	Garrett	MG2.5			(5,505,652)
24	To Remove Supplemental Executive Retirement Plan	Garrett	MG2.6			(1,713,195)
25	To Reverse Adjustment for Affiliate Expense Allocation	Garrett	MG2.7			(5,579,128)
26	To Reverse OG&E Estimated Ad Valorem Adjustment	Garrett	MG2.8			(4,166,889)
27	To Limit Vegetation Management to 5-Year Average Spend	Garrett	MG2.13			(5,983,404)
28	Total Operating Revenue & Expense Adjustments					<u>\$ (41,973,633)</u>
29	Depreciation and Amortization Expense Adjustments					
30	To Amortize Stranded Smart-Grid Meters over 15 Years	Garrett	MG2.12			(3,679,140)
31	To Adjust Expense for OIEC/OER Depreciation Rates	Pous	MG2.10			<u>\$ (37,298,897)</u>
32	Total Depreciation and Amortization Expense Adjustments					<u>\$ (40,978,036)</u>
33	Total of All OIEC/OER Adjustments					<u>\$ (125,169,481)</u>
34	OIEC/OER Proposed Rate Decrease					<u><u>\$ (32,674,789)</u></u>

OKLAHOMA GAS & ELECTRIC COMPANY
OIEC WORKPAPERS - ADJUSTMENT TO PENSION BENEFIT ASSET BALANCE
 Test Year Ended 6-30-15
 Cause NO. PUD 201500273

Line No.	Description	OG&E Requested Balance	Ref.	Actual Book Balance at 12/31/2015	Ref.	OIEC Total Co Adjustment	OIEC Okla Juris Adjustment
							92.33%
1	Prepaid Pension Asset (Acct 182.3)	\$ 254,186,790	Sch G-6	\$ 242,232,668	OIEC 13-1 Att	\$ (11,954,122)	
2	Deferred Tax On Prepaid Pension	\$ (66,562,736)	W/P J-4 (Ln 31,31a)	\$ (55,737,561)	AG 19-5 Att W/P J-4	\$ 10,825,175	
3	OPEB Liability (Account (228.3))	\$ (174,015,692)	Sch G-6	\$ (179,925,299)	OIEC 13-1 Att	\$ (5,909,607)	
4	Deferred Tax On OPEB Balances	\$ 41,366,040	W/P J-4 (Ln 1,2,12)	\$ 41,421,563	AG 19-5 Att W/P J-4	\$ 55,523	
5	Total Net Pension / OPEB Balance	<u>\$ 54,974,401</u>	Sch B-2	<u>\$ 47,991,371</u>		<u>\$ (6,983,030)</u>	<u>\$ (6,447,432)</u>

OKLAHOMA GAS & ELECTRIC COMPANY
OIEC WORKPAPERS - ADJUSTMENT TO OG&E'S PRO FORMA PAYROLL EXPENSE
 Test Year Ended 06-30-15
 Cause NO. PUD 201500273

Ln	Description	Ref	Amount	Okla Juris	Okla Amount
				(Sch H-1)	
1	Reverse OG&E's Adj. to increase OG&E Test Year Payroll Expense by :	W/P H-2-23	\$ (4,229,523)	90.21%	\$(3,815,453)
2	Reverse OG&E's Adj. to increase Holding Co. T/Y Payroll Expense by 1	W/P H-2-23	\$ (1,420,980)	90.21%	\$(1,281,866)
3	Total OIEC Adjustment to Reverse OG&E's Payroll Adjustments	Calc.	\$ (5,650,503)	90.21%	\$(5,097,319)
4	Effective Payroll Tax Rate	W/P H-2-23a	7.02%		
5	OIEC Adjustment for Payroll Tax Expense on OG&E's Payroll Adjustme	Calc.	\$ (396,720)	90.21%	\$(357,881)
6	TOTALS		\$ (6,047,223)		\$(5,455,199)

OG&E Response to OIEC 1-4 Supplement

	2011	2012	2013	2014	Test Year	2015	Difference
a. OG&E general payroll	148,270,231	151,223,200	146,978,465	149,882,987	153,109,406	154,283,189	
b. OG&E general payroll expensed at OG&E	98,384,854	97,022,487	99,784,338	100,960,835	102,930,518	103,021,765	\$ 91,247 0.089%
d. OG&E overtime payroll	17,466,801	16,261,772	17,915,133	16,049,215	16,332,831	18,439,326	
e. OG&E overtime payroll expensed at OG&E	9,926,751	9,050,109	10,722,287	9,803,434	9,530,541	10,584,778	1,054,237
g. Number of employees	2,108	1,987	1,885	1,884	1,884	1,888	

OG&E Response to OIEC 1-3 Supplement

	2011	2012	2013	2014	Test Year	2015		
a. Holding Co. general payroll	43,504,541	43,847,205	46,078,094	44,112,860	43,935,940	44,098,476		
b. Holding Co. payroll allocated to OG&E	36,751,670	37,285,851	39,528,249	40,138,111	40,204,914	40,214,033		
d. Holding Co. payroll expensed at OG&E	27,338,240	28,055,473	30,585,898	31,530,050	31,564,686	31,187,015	\$ (377,670) -1.196%	
e. Holding Co. overtime payroll	961,147	980,823	1,069,777	739,865	780,855	844,176		
g. Holding Co. overtime allocated to OG&E	850,698	867,432	986,186	671,199	721,119	790,683		
h. Holding Co. overtime expensed at OG&E	450,298	550,523	643,786	465,333	526,109	532,975	6,865	
i. Holding Co. number of employees	1,381	1,390	604	561	530	532		
						Payroll Plus Overtime Taxes	774,679 54,390	698,838 49,065
						OIEC Adjustment if Overtime is Included Taxes	\$ (4,875,824) \$ (342,330)	\$ (4,398,481) \$ (308,816)
							<u>\$ (5,218,154)</u>	<u>\$ (4,707,297)</u>

OKLAHOMA GAS & ELECTRIC COMPANY
OIEC WORKPAPERS - ADJUSTMENT TO INCENTIVES EXPENSE
Test Year Ended 6-30-15
Cause NO. PUD 201500273

Line No.	(a) Description	(b) Source	(c) OGE Holding Company	(d) OG&E Utility	(e) Total	(f) Amount Excluded	(g) Test Year Incentives Excluded
1	Annual Incentives	W/P H-2-24	\$ 6,954,257	\$ 14,084,309	\$ 21,038,566		
2	Expensed Portion	W/P H-2-24	65.54%	77.18%			
3	Annual Incentives in Pro Forma Expense		\$ 4,557,819	\$ 10,870,095	\$ 15,427,914	50.00%	\$ 7,713,957
4	Oklahoma Jurisdictional Allocation	Sch H-1					<u>92.10%</u>
5	OIEC Adjust. to Oklahoma Incentive Expense						<u>\$ 7,104,554</u>
6	Payroll Tax Percentage	W/P H-2-24					7.02%
7	OIEC Adjustment for Payroll Taxes on Oklahoma Incentive Expense						<u>\$ 498,740</u>
8	Long-term Incentives	W/P H-2-24	\$ 5,960,675	\$ 2,683,746	\$ 8,644,421		
9	Expensed Portion	W/P H-2-24	65.54%	77.18%			
10	Long-term Incentives in Pro Forma Expense		\$ 3,906,625	\$ 2,071,282	\$ 5,977,907	100.00%	\$ 5,977,907
11	Oklahoma Jurisdictional Allocation	Sch H-1					<u>92.10%</u>
12	OIEC Adjustment to Oklahoma Incentive Expense						<u>\$ 5,505,652</u>

OKLAHOMA GAS & ELECTRIC COMPANY
OIEC WORKPAPERS - ADJUSTMENT TO SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN EXPENSE
Test Year Ended 6-30-15
Cause NO. PUD 201500273

Line No.	Description	OGE Parent Holding Co.	OG&E Utility Co.	AG 2-34_Att	TOTAL
1	Supplemental Executive Retirement Plan Costs	\$ 1,642,899	\$ 217,248		\$ 1,860,147
2	Expense %				<u>100.00%</u>
3	Total Company SERP in Cost of Service				<u>\$ 1,860,147</u>
4	OIEC Adjustment to Remove SERP Expense				<u>\$ (1,860,147)</u>
5	Oklahoma Jurisdictional %				92.10%
6	OIEC Adjustment to Remove Oklahoma SERP Expense				<u><u>\$ (1,713,195)</u></u>

OKLAHOMA GAS & ELECTRIC CO
 OIEC WORKPAPERS - Affiliate Expense Adjustment
 Test Year Ended 06-30-15
 Cause NO. PUD 201500273

<u>Ln</u>	<u>Description</u>	<u>Source</u>	<u>Total Co</u>	<u>Juris %</u>	<u>Oklahoma</u>
1	OG&E's Adjustment to include Affiliate Costs	WP H-2-22	\$ 6,057,685	92.10%	\$ 5,579,128
2	Affiliate Costs Allowable within Test Year or 6-Month Cutoff		\$ -		\$ -
3	OIEC/OER Adjustment to Remove Affiliate Costs outside the Test Year		<u>\$ (6,057,685)</u>		<u>\$ (5,579,128)</u>

OKLAHOMA GAS & ELECTRIC CO
OIEC WORKPAPERS - ADJUSTMENT TO AD VALOREM TAX EXPENSE
Test Year Ended 06-30-15
Cause NO. PUD 201500273

<u>Ln.</u>	<u>Description</u>	<u>Ref.</u>	<u>Amount</u>	<u>Juris %</u>	<u>Okla</u>
1	OG&E Test Year Ad Valorem Tax Expense Adjustment	WP H2.17	\$ 4,624,225		
2	OIEC/OER Adjustment to Reverse OG&E's Estimated Adj.	(Sch H-1)	\$ (4,624,225)	90.11%	<u>\$ (4,166,889)</u>

OKLAHOMA GAS & ELECTRIC CO
OIEC WORKPAPERS - ADJUSTMENT FOR LOAD GROWTH THROUGH 6-MONTH UPDATE PERIOD
Test Year Ended 06-30-15
Cause NO. PUD 201500273

<u>Ln.</u>	<u>Description</u>	<u>Ref.</u>	<u>Oklahoma Revenues</u>
1	OG&E Load Growth Adjustment filed with Application for Growth through June 30, 2015	W/P H-2b Summary	\$ 12,511,435
2	OG&E Load Growth Adjustment for Growth through December 31, 2015	AG 2-10 Supp	<u>\$ 17,886,497</u>
3	Additional Adjustment Needed to Recognize Load Growth through December 31, 2015		<u>\$ (5,375,062)</u>

OKLAHOMA GAS & ELECTRIC COMPANY
OIEC WORKPAPERS - ADJUSTMENT TO DEPRECIATION EXPENSE
Test Year Ended 6-30-15
Cause NO. PUD 201500273

Line No.	Acct No.	Description	Plant In Service 12/31/2015	OIEC Rates	OIEC Depreciation Expense	OG&E Depreciation Expense	OIEC Adjustment
1		References	AG 1-14 Supp Final	J. Pous	Calc.	Sch I-1-1	Calc.
2							
3		INTANGIBLE PLANT					
4	301	Organization					
5	302	Franchise and Consents	2,629,045	4.22%	\$ 110,946		
6	303	Miscellaneous Intangible Plant	70,715,175	*	1,263,937		
7		TOTAL INTANGIBLE PLANT	\$ 73,344,220				
8							
9		STEAM PRODUCTION					
10	310	Land and Land Rights	968,004	2.86%	27,685		
11	311	Structures and Improvements	269,450,775	1.81%	4,877,059		
12	312	Boiler Plant Equipment	1,106,584,555	1.71%	18,922,596		
13	314	Turbogenerator Units	429,747,622	2.00%	8,594,952		
14	315	Accessory Electric Equipment	147,146,698	1.63%	2,398,491		
15	316	Miscellaneous Power Plant Equipment	34,580,712	2.35%	812,647		
16	317	ARO Cost - Steam Production	5,476,311	1.42%	77,764		
17		TOTAL STEAM PRODUCTION	\$ 1,993,954,678				
18							
19		OTHER PRODUCTION					
20	340	Land and Land Rights	-	2.86%	-		
21	341	Structures and Improvements	65,861,504	2.52%	1,659,710		
22	342	Fuel Holders, Producers and Accessories	14,881,602	2.19%	325,907		
23	343	Prime movers	569,115,008	4.09%	23,276,804		
24	344	Generators	833,477,886	3.29%	27,421,422		
25	345	Accessory Electric Equipment	110,981,953	2.77%	3,074,200		
26	346	Miscellaneous Power Plant Equipment	8,626,299	2.84%	244,987		
27	347	ARO Cost - Other Production	43,620,335	0.92%	401,307		
28	114	Acquisition Adjustment - Redbud	148,301,899				
29		TOTAL OTHER PRODUCTION	\$ 1,794,866,487				
30							
31		TRANSMISSION PLANT					
32	350	Land and Land Rights	110,986,098	0.97%	1,076,565		
33	352	Structures and Improvements	7,246,425	1.67%	121,015		
34	353	Station Equipment	685,546,748	1.75%	11,997,068		
35	354	Towers and Fixtures	160,178,524	1.40%	2,242,499		
36	355	Poles and Fixtures	845,512,127	2.23%	18,854,920		
37	356	Overhead Conductors and Devices	568,342,215	2.29%	13,015,037		
38	358	Underground Conductors and Devices	110,494	0.27%	298		
39	359	ARO Cost - Transmission	585,057	1.01%	5,909		
40	114	Acquisition Adjustment - Edmond Substatic	3,341,804				
41		TOTAL TRANSMISSION PLANT	\$ 2,381,849,492				
42							
43		DISTRIBUTION PLANT					
44	360	Land and Land Rights	5,129,299	1.53%	78,478		
45	361	Structures and Improvements	7,168,702	1.71%	122,585		
46	362	Station Equipment	598,323,077	2.16%	12,923,778		
47	364	Poles, Towers, and Fixtures	592,206,901	2.89%	17,114,779		
48	365	Overhead Conductors and Devices	460,944,161	2.69%	12,399,398		
49	366	Underground Conduit	205,322,655	2.20%	4,517,098		
50	367	Underground Conductors and Devices	725,544,729	1.95%	14,148,122		
51	368	Line Transformers	434,228,664	3.44%	14,937,466		
52	369	Services	241,866,312	2.01%	4,861,513		
53	370	Meters	171,166,575	6.52%	11,160,061		
54	371	Installation on Customers' Premises	48,882,585	21.81%	10,661,292		
55	372	Leased Property on Customer's Premises	-				
56	373	Street Lighting and Signal Systems	229,085,496	5.18%	11,866,629		
57		TOTAL DISTRIBUTION PLANT	\$ 3,719,869,156				
58							
59		GENERAL PLANT					
60	389	Land and Land Rights	147,826	2.74%	4,050		
61	390	Structures and Improvements	177,947,733	1.52%	2,704,806		
62	391	Office Furniture and Equipment	19,610,608	8.61%	1,688,473		
63	392	Transportation Equipment	80,442,109	5.19%	4,174,945		
64	393	Stores Equipment	1,081,457	4.00%	43,258		
65	394	Tools, Shop and Garage Equipment	11,250,189	4.00%	450,008		
66	395	Laboratory Equipment	12,233,921	5.00%	611,696		
67	396	Power Operated Equipment	8,967,576	4.86%	435,824		
68	397	Communication Equipment	22,590,240	10.00%	2,259,024		
69	398	Miscellaneous Equipment	6,141,910	5.00%	307,096		
70		TOTAL GENERAL PLANT	\$ 340,413,570				
71							
72		TOTAL ELECTRIC PLANT IN SERVICE	\$ 10,304,297,602				
73							
74		Remove Transportation Activity Depr	\$ 4,174,945	49.88%	(2,082,463)		
75							
76		Holding Company	\$ 139,020,441	5.32%	7,395,887		
77		TOTAL COMPANY	\$ 10,443,318,043		\$ 273,587,531	314,602,372	\$ (41,014,841)
78							
79		OIEC Adjustment - Oklahoma Jurisdiction		90.94%	Sch H-1		\$ (37,298,897)

OKLAHOMA GAS & ELECTRIC CO
OIEC WORKPAPERS - ADJUSTMENT TO RECOGNIZE GAIN ON SALE OF UTILITY ASSETS
Test Year Ended 6-30-15
Cause NO. PUD 201500273

<u>Ln.</u>	<u>Description</u>	<u>Date</u>	<u>Account</u>	<u>Ref.</u>	<u>OIEC Adjustment</u>
1	Gain on Sale of McClain Rotor to GE	12/31/2015	254	Exhibit MG2.1	\$ (944,309)
2	2-Year Amortization of Gain into Rates				<u>12</u>
3	Annual Increase to Revenue to Recognize Gain Amortization				\$ (472,154)
4	Gain on Sale of Distribution Facilities to Choctaw Nation	6/30/2015	421	OIEC 3-25	\$ (119,654)
5	OIEC Adjustment to Recognize Gains				<u>\$ (591,808)</u>

**OKLAHOMA GAS AND ELECTRIC COMPANY
OIEC ADJUSTMENT - SMART GRID STRANDED COST AMORTIZATION
TEST YEAR ENDING 6/30/15
CAUSE NO. PUD 201500273**

Line No.	Description	FERC Account	Source	OG&E 6-Year Amortization	OIEC 15-Year Amortization	OIEC Adjustment
1	Annual Amortization on Stranded Meters	920	W/P H-2-41	\$ 5,721,613	\$ 2,288,645	\$ (3,432,968)
2	Annual Amortization of Smart Grid Web Portal	920	W/P H-2-41	<u>1,021,184</u>	<u>\$ 408,474</u>	<u>\$ (612,710)</u>
3	Total Annual Amortization			\$ 6,742,797	\$ 2,697,119	<u>\$ (4,045,678)</u>
4	Oklahoma Jurisdictional Allocation					90.94%
5	Total Annual Amortization					<u>\$ (3,679,140)</u>

PURPOSE:

To Change OG&E's proposed 6-year amortization of stranded meters and Smart Grid Web Portal cost to a 15-year amortization. (The 6-year amortization is from Stipulation adopted in Order # 576595 in PUD Docket No. 201000029 - not followed by OG&E).

**OKLAHOMA GAS AND ELECTRIC COMPANY
OIEC ADJUSTMENT - VEGETATION MANAGEMENT
TEST YEAR ENDING 6/30/15
CAUSE NO. PUD 201500273**

Line No.	Description	Ref	Test Year Expense	OG&E Requested Spend	% Increase	Average 5-Year Spend	OIEC Adjustment
1	Distribution	W/P H2.43	\$ 14,272,378	\$ 25,790,903	81%	\$ 21,500,000	\$ (4,290,903)
2	Transmission	W/P H2.45	\$ 2,842,153	\$ 4,534,654	60%		<u>\$ (1,692,501)</u>
3	Total						<u><u>\$ (5,983,404)</u></u>

PURPOSE:

To limit the increase in Distribution Vegetation Management to the 5-Year average spend level.
To limit the increase in Transmission Vegetation Management Expense to the test year level.

OKLAHOMA GAS & ELECTRIC CO
OIEC WORKPAPERS - COST OF CAPITAL
Test Year Ended 6-30-15
Cause NO. PUD 201500273

OG&E Proposed

Ln.	Description	Cap Struc	Cost	Wt Avg	Tax	ROR
1	Long Term Debt	46.69%	5.62%	2.624%	1.00000	2.624%
2	Preferred	0.00%	0.00%	0.000%		
3	Common Equity	53.31%	10.25%	5.464%	1.633266	8.924%
4		100.000%		8.088%		11.548%

OIEC Proposed

Ln.	Description	Cap Struc	Cost	Wt Avg	Tax	ROR
1	Long Term Debt	46.69%	5.62%	2.62%	1.00000	2.62%
2	Preferred	0.000%	0.00%	0.00%		
3	Common Equity	53.31%	9.000%	4.80%	1.633266	7.84%
4		100.000%		7.42%		10.46%