

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

**APPLICATION OF THE EMPIRE DISTRICT)
ELECTRIC COMPANY, A KANSAS)
CORPORATION, FOR AN ADJUSTMENT IN)
ITS RATE AND CHARGES FOR ELECTRIC)
SERVICE IN THE STATE OF OKLAHOMA)**

CAUSE NO. PUD 201600468

**RESPONSIVE TESTIMONY
OF
MARK E. GARRETT**

REVENUE REQUIREMENT ISSUES

**ON BEHALF
OF**

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS ("OIEC")

March 13, 2017

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

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

2 A: My name is Mark 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: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**
10 **PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION?**

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

1 the Oklahoma Corporation Commission from 1991 to 1995. In that position, I managed
2 the audits of major gas and electric utility companies in Oklahoma.

3 Since leaving the Commission, I have worked on numerous rate cases and other
4 regulatory proceedings on behalf of various consumers, consumer groups, public utility
5 commission staffs and attorney general's offices. I have provided both written and live
6 oral testimony before public utility commissions in the states of Alaska, Arizona,
7 Arkansas, Colorado, Massachusetts, Nevada, Oklahoma, Texas and Utah, and written
8 testimony in the state of Florida. My qualifications were accepted in each of those
9 states. My clients primarily include large industrial customers, large hotels in Nevada,
10 large hospitals and hospital groups, universities, municipalities, large commercial
11 customers and solar industry interveners. I have also testified on behalf of the
12 commission staff in Utah and the offices of attorneys general in Oklahoma and Florida.
13 I have also served as a presenter at the NARUC subcommittee on Accounting and
14 Finance on the issue of incentive compensation, and as a regular instructor at the New
15 Mexico State University's Center for Public Utilities course on basic utility regulation.

16
17 **Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THIS COMMISSION**
18 **IN PROCEEDINGS DEALING WITH REVENUE REQUIREMENT ISSUES?**

19 **A:** Yes, they have. A more complete description of my qualifications and a list of the
20 proceedings in which I have been involved before this Commission and other public
21 utility commissions is attached to this testimony as Exhibit MG-1.

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

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

3

4 Q: WHO IS OIEC?

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

8

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

10 A: OIEC members purchase substantial quantities of electric power which are necessary for
11 their operations. Electric power costs can constitute a significant percentage of industrial
12 and other large consumers' operating costs. These electric power supplies are generally
13 purchased from utilities pursuant to standard tariffs filed at the Commission. Industries
14 served by utilities such as Empire District Electric Company, ("Empire" or "the
15 Company"), operate in competitive business environments and, thus, are interested in the
16 Commission determining rates that result in the delivery of reliable power at the lowest
17 and most reasonable cost possible under the circumstances.

18

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

20 A: I provide the Commission with recommendations regarding Empire's prospective
21 revenue requirement. I also sponsor *Exhibit MG 2* in which the overall impact of my
22 revenue requirement recommendations is set forth.

1 **II. EMPIRE'S PROPOSED RATE INCREASE/ OIEC'S RESPONSE**

2 **Q: WHAT IS THE COMPANY RECOMMENDING IN THIS CASE?**

3 A: Empire is recommending an approximate \$3.8 million increase in Oklahoma.¹ This
4 represents a 45.26%² increase in base rates and a 27.58%³ increase in overall rates.
5 According to the Company, the requested increase is primarily driven by new capital
6 investment to comply with Environmental Protection Agency ("EPA") air quality
7 regulations.⁴ Specifically, Empire invested in a bag house and scrubber system at its
8 Asbury plant, retired two coal units and converted a simple-cycle gas plant to a
9 combined-cycle plant at Riverton 12.⁵ The total environmental investment at Asbury
10 and Riverton 12 was about \$304 million.⁶

11
12 **Q: WHEN WAS THE COMPANY'S LAST RATE CASE IN OKLAHOMA?**

13 A: Empire's last rate case was Cause No. PUD 201100082, using an updated test year of
14 June 30, 2011. The rates from that rate case took effect January 2012.

15
16 **Q: IS EMPIRE'S REQUEST FOR A 45.26% INCREASE IN BASE RATES AND A
17 27.58% INCREASE IN OVERALL RATES REASONABLE?**

18 A: No. Empire's requested increase is unconscionable, not to mention, irresponsible. A
19 10% base rate increase is generally considered to constitute rate shock. This means a

¹ See Application at page 1. See also Schedule M-1.

² See Schedule M-1 ($\$3,819,045 / \$8,437,640 = 45.26\%$).

³ See Application at page 1 and Schedule M-1.

⁴ See Owens Direct Testimony at page 3, starting at line 16.

⁵ See Application at page 2 paragraph 5.

1 45.26% increase would constitute rate shock nearly five times over. Since its last rate
2 case in 2011, Empire has been investing large amounts in new rate base with no notice to
3 the Commission or to the Company's customers. In my opinion, it is irresponsible for a
4 utility to sit quietly for five years before it inform its customers that it intends to nearly
5 double their base rates.

6 Regarding overall rates, a 27.58% increase in a 5-year period is also
7 unreasonable. This amounts to an average annual increase of 5.5%. For purposes of
8 comparison, the Consumer Price Index ("CPI") rose by an annual average increase of
9 1.32% over the period 2012 to 2016. Thus, Empire's requested increase is more than 4
10 times the CPI average.

11
12 **Q: HAS EMPIRE REQUESTED SIMILARLY LARGE RATE INCREASES IN ANY**
13 **OTHER STATES IN WHICH IT OPERATES?**

14 A: Yes. Empire requested a comparably large rate increase of 25.64% in Kansas last year, a
15 jurisdiction in which, like Oklahoma, Empire had not filed a rate case since 2011.⁷ The
16 increase in Kansas was driven by the same two factors driving the requested increase in
17 Oklahoma, which included (1) the large increase for the Asbury and Riverton 12
18 environmental improvements; and (2) Empire's failure to timely file rate cases.

19
20 **Q: WHAT WAS THE OUTCOME IN THE KANSAS RATE CASE?**

21 A: Empire withdrew its application in that docket.

⁶ See Application at page 2 and the Direct Testimony of Owens at page 5, lines 7-11.

⁷ Docket No. 16-EPDE-101-RTS.

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Q: WHY DID EMPIRE WITHDRAW ITS KANSAS RATE CASE?

A: Pursuant to a Unanimous Settlement Agreement in Docket No. 16-EPDE-410-ACQ (“410 Docket”) before the Kansas Corporation Commission (KCC), involving Empire’s application for approval of a merger with Liberty Utilities (Central) Co., the KCC authorized the following: (1) Empire’s withdrawal of its Kansas rate case, (2) a moratorium on another rate case filing until May 1, 2018, and (3) collection of the Asbury and Riverton 12 capital costs through an environmental compliance rider, subject to refund and an annual true-up. Thus, the agreement reached in Kansas and approved by the KCC was that Empire would be allowed to recover its Asbury and Riverton 12 capital cost increases, and nothing more.

Q: ARE THE TERMS THAT EMPIRE AGREED TO IN KANSAS A REASONABLE OUTCOME FOR OKLAHOMA RATEPAYERS IN THIS PROCEEDING?

A: The terms of the Kansas settlement are certainly more reasonable than Empire’s requested Rate Application in Oklahoma. Before this Commission considers Empire’s requested increase, the Company must address the appropriateness of Oklahoma ratepayers incurring significantly higher rate increases than those received by Kansas ratepayers.

Q: COULD THE COMMISSION ADOPT THESE SAME TERMS IN OKLAHOMA?

A: Yes. Empire has already indicated by its agreement to these terms in Kansas that it

1 believes these terms result in *just and reasonable* rates, and the KCC in its order
2 approving the settlement in the 410 Docket also determined that the terms resulted in *just*
3 *and reasonable* rates.
4

5 **Q: IS IT PERMISSIBLE TO REFERENCE THE KANSAS SETTLEMENT**
6 **AGREEMENT TO SHOW THAT EMPIRE AGREED WITH THE KANSAS**
7 **TERMS?**

8 A: Yes. It is permissible to reference the terms of an approved and implemented settlement
9 agreement for the purpose of showing that a utility agreed to the terms of that agreement.
10 It is also particularly appropriate to reference the Kansas settlement in this case because
11 of the close proximity in time, and the similarity of jurisdictional impact on Empire's
12 total company operations. In other words, Empire's Oklahoma ratepayers comprise an
13 even smaller jurisdictional percentage of its overall service territory than its Kansas
14 ratepayers do. Thus, the impact of implementing the same terms in Oklahoma as in the
15 Kansas settlement will have no greater financial impact on Empire. The converse,
16 however, is not true. If the Oklahoma Commission were to approve Empire's requested
17 rate increase in this docket, the Oklahoma ratepayers in Empire's service territory would
18 suffer a tremendous adverse financial impact due to the unreasonable increases in their
19 electric utility rates.
20

21 **Q: WHAT ARE THE CAPITAL COSTS FOR THE ASBURY AND RIVERTON 12**
22 **ENVIRONMENTAL COMPLIANCE?**

1 A: The Oklahoma jurisdictional portion of the Asbury and Riverton 12 environmental
 2 compliance capital expenditures is set forth in Table 1 below and can be seen in more
 3 detail at Exhibit MG-2:

EMPIRE DISTRICT ELECTRIC COMPANY OIEC WORKPAPERS - CAPITAL COST RECOVERY FOR ASBURY AND RIVERTON 12 Test Year Ended June 30, 2016 Cause No. PUD 201600468					
Line	Description	Asbury	Riverton 12	Total	Oklahoma
					2.75%
1	Plant in Service	\$ 122,292,465	\$ 181,640,749	\$ 303,933,214	\$ 8,364,242
2	Accumulated Depreciation	(11,476,271)	(2,344,710)	(13,820,981)	(380,353)
3	ADIT	(22,144,455)	(34,641,953)	(56,786,408)	(1,562,762)
4	Total	\$ 88,671,739	\$ 144,654,086	\$ 233,325,825	\$ 6,421,127
5	Pre-Tax Rate Of Return				9.79%
6	Return				\$ 628,406
7	Depreciation Expense	\$ 2,283,425	\$ 4,104,607	\$ 6,388,032	\$ 175,799
8	ECP Rider Revenues - Year 1				\$ 804,205

4 As shown in the table above, the Net Plant in Service for the Asbury and Riverton 12
 5 additions, after deductions for accumulated depreciation and ADIT, is \$233,325,825.
 6 The Oklahoma jurisdictional amount of Net Plant in Service is \$6,421,127. Assuming a
 7 pre-tax rate of return of 9.79%, which is OIEC's recommended rate of return, the annual
 8 return and depreciation expense on the Asbury and Riverton 12 net plant balances would
 9 be \$804,205. If a rider is authorized for collection of these costs, the costs should be
 10 distributed to Empire's rate classes based on the current revenues in each class and
 11 collected then on a kWh basis.

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Q: PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING EMPIRE'S REQUESTED RATE INCREASE?

A: I believe that the Commission could authorize a rider for Empire's collection of the capital costs of the Asbury and Riverton 12 projects, subject to refund and subject to a Commission review for prudence of these investments in Empire's next Oklahoma rate case. All other cost increases should be rejected at this time and could be considered in Empire's next Oklahoma rate case filing, which is consistent with the actions of the KCC.

III. REVENUE REQUIREMENT ISSUES

Q: IF THE COMMISSION DOES NOT ADOPT THE RECOMMENDATION TO AUTHORIZE AN ECP RIDER FOR RECOVERY OF THE CAPITAL COSTS ASSOCIATED WITH THE ASBURY AND RIVERTON 12 ENVIRONMENTAL COMPLIANCE UPGRADES, ARE THERE ISSUES REGARDING EMPIRE'S PROPOSED REVENUE REQUIREMENT INCREASE?

A: Yes. Although I do not recommend this path, if the Commission decides not to (i) adopt the ECP rider for recovery of Asbury and Riverton 12 capital costs and (ii) reject all other proposed revenue requirement increases, there are numerous other adjustments to Empire's proposed revenue requirement the Commission would need to make, including the adjustments discussed in the Section 3 below.

III. A. INVESTMENT LEVELS UPDATED TO 6-MONTH BALANCES

III. A. (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, 2016 and the 6-month cut-off for post-test year
6 adjustments is December 31, 2016. 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, 2016?**

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, 2016.
13 The Company's requested level includes actual Plant in Service balances at test year end,
14 and an estimated amount the Company expected to be in service within six months after
15 test year. My adjustment reflects the *actual* plant balances at December 31, 2016.

16
17 **Q: IS THE ADJUSTMENT TO ACTUAL BALANCES AT THE 6-MONTH 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
20 was adopted was in ONG's 2004 rate case, Cause No. PUD 200400610, in which the

1 ALJ adopted the approach, no party appealed the recommendation, and the Commission
2 accepted and approved the ALJ's recommendation. In that proceeding, after a hearing
3 on the merits, the ALJ updated QNG's Plant in Service and Accumulated Depreciation
4 balances through the six month period following test year end. Projects still in the CWIP
5 accounts at that time were specifically excluded. In OG&E's 2005 rate case, PUD
6 200500151, the Commission again updated the Plant and Accumulated Depreciation
7 balances to six months after test year end and appropriately excluded CWIP on the books
8 at that time. In PSO Cause Nos. PUD 200600285, PUD 200800144, and PUD
9 201500208 the Commission also followed this approach. In OG&E's last rate case,
10 Cause No. PUD 201100087, which was resolved by case settlement, the ALJ
11 recommended this approach in her Report prior to the Parties' settlement of the case.
12

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

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

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, 2016
8 Plant in Service balance is set forth below and can be seen at Exhibit MG-2.

Description	OIEC Adjustment Increase (Decrease) to Actual Balance at 12/31/2016	Oklahoma Jurisdictional Amount
Plant in Service	\$930,891	\$99,489

III. A. (2) ACCUMULATED DEPRECIATION

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

11 A: Yes. When the investment in Plant in Service is updated to the actual levels as of the six
12 month cut off, it is also necessary to adjust changes in the investment levels related to
13 off-setting accounts such as Accumulated Depreciation and Accumulated Deferred
14 Income Tax (ADIT). These adjustments have been consistently accepted by the
15 Commission in recent rate case proceedings, and are consistent with Oklahoma law.
16 (Title 17 § 284). The necessary adjustment to reflect the actual December 31, 2016
17 Accumulated Depreciation balance is set forth below and can be seen at Exhibit MG-2.

Description	OIEC Adj. Increase (Decrease) to Actual Balance at 12/31/2016	Oklahoma Jurisdictional Amount
Accumulated Depreciation	\$(1,258,151)	\$(134,465)

1 This adjustment updates the Company's Accumulated Depreciation balance to the
2 December 31, 2016 levels, and is necessary to give effect to the known and measurable
3 decrease in the Accumulated Depreciation balance that occurred within six months of
4 test year end.

5
III. A. (3) ACCUMULATED DEFERRED INCOME TAXES (ADIT).

6 **Q: WHAT ADJUSTMENT ARE YOU PROPOSING FOR ACCUMULATED**
7 **DEFERRED INCOME TAXES?**

8 A: This adjustment updates the Company's Accumulated Deferred Income Tax ("ADIT")
9 balances to the December 31, 2016 levels. This adjustment is necessary to give effect to
10 the known and measurable increase in the deferred tax balances that occurred within six
11 months of test year end. When additions to the investment levels in Plant in Service are
12 recognized through the six month cut off, changes in the investment levels related to
13 ADIT must be recognized as well. This adjustment has been accepted previously by the
14 Commission, and is consistent with Oklahoma law (Title 17 § 284). The necessary
15 adjustment is set forth below.

Description	OIEC Increase(Decrease) To Actual Balance at 12/31/2016	Oklahoma Jurisdictional Amount
ADIT	\$(688,836)	\$(73,619)

III. A. (4) CUSTOMER DEPOSITS AND PREPAYMENTS

Q: HAVE YOU PROPOSED AN ADJUSTMENT TO CUSTOMER DEPOSITS AND PREPAYMENTS?

1 A: Yes. Adjustments to the Company's Customer Deposits and Prepayments accounts are
2 necessary to give effect to the known and measurable changes that occurred within six
3 months of test year end, as has been accepted by the Commission in recent rate case
4 proceedings, and is consistent with Oklahoma law. The adjustments necessary to reflect
5 the actual December 31, 2016 balances are set forth in the table below. The detailed
6 calculations are shown at *Exhibit MG 2.1* attached to this testimony.

Description	OIEC Increase (Decrease) To Actual Balances at 12/31/2016	Oklahoma Jurisdictional Amount
Customer Deposits	\$(2,342)	\$(250)
Prepayments	\$22,003	\$2,352

III. A. (5) MATERIALS & SUPPLIES

7 **Q: ARE YOU PROPOSING AN ADJUSTMENT TO UPDATE THE MATERIALS &**
8 **SUPPLIES ACCOUNT TO INCLUDE MONTHLY DATA THROUGH THE SIX**
9 **MONTH CUTOFF?**

10 A: Yes. The Company has provided data for this account through December 31, 2016 to
11 update accounts to be included in rate base. This adjustment can be seen at Exhibit MG-
12 2.

Description	OIEC Increase (Decrease) To Actual Balance 12/31/2016	Oklahoma Jurisdictional Amount
Materials & Supplies	\$(38,942)	\$(4,162)

13 **Q: MUST EVERY INVESTMENT, EXPENSE AND REVENUE ACCOUNT BE**

1 **UPDATED TO DECEMBER 31, 2016 TO COMPLY WITH TITLE 17 § 284?**

2 A: No. Practically speaking, only accounts with known and measurable changes of a
3 material amount need to be updated to comply with Title 17§ 284.

III. B. (1) ANNUAL INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

4 **Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF EMPIRE'S ANNUAL**
5 **INCENTIVE COMPENSATION PLAN.**

6 A. Empire provides an annual cash incentive compensation plan to all employees and seeks
7 to include the costs of that plan in rates.

8
9 **Q: WHAT ADJUSTMENT ARE YOU PROPOSING WITH RESPECT TO THE**
10 **COMPANY'S ANNUAL INCENTIVE PLAN?**

11 A: I am proposing to exclude 100% of the annual incentive plan expense. This treatment
12 removes all of the incentive-plan costs associated with financial performance measures,
13 because incentive plan costs associated with financial performance are traditionally
14 removed from rates,⁸ and it also removes all of the incentive-plan costs associated with

⁸ 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 customer satisfaction and reliability, because Empire has performed so poorly in these
2 areas over the past several years.

3
4 **Q: WHAT IS THE GENERAL RATIONALE FOR EXCLUDING INCENTIVE**
5 **COMPENSATION TIED TO FINANCIAL PERFORMANCE?**

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

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

18 (2) **Many of the factors that significantly impact earnings are outside the control**
19 **of most company employees and have limited value to customers.** For
20 example, an unusually hot summer can easily trigger an incentive payment based
21 on company earnings for an electric utility, as a cold winter can for a gas utility.
22 Obviously, weather conditions are outside the control of utility employees and
23 customers receive no benefit from the higher utility bills that result from an
24 unusually hot or cold weather. Similarly, company earnings may increase, thus
25 triggering incentive payments, as a result of customer growth, which commonly
26 occurs without significant influence from company personnel. In fairness, since
27 shareholders enjoy the benefits of customer growth between rate cases,
28 shareholders should also bear the cost of any incentive payments such growth
29 may trigger. Finally, utility earnings may increase substantially if the utility is

⁹ 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 able to successfully argue for a higher ROE in a rate case proceeding. Utility
2 efforts to maximize ROE in a rate proceeding, however, have little to do with
3 improving overall employee performance across the company. If utility
4 employees gear their efforts toward securing an *unreasonably* high ROE in a rate
5 proceeding, the incentive mechanism actually would work to the detriment of the
6 utility customers.

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

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

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

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

¹⁰ This occurred in PSQ'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.

1 in rates is not needed. In those years when financial performance measures are
2 not met and the incentive payments are not made, the amount embedded in rates
3 for incentive payments acts as a financial hedge to shelter the poor financial
4 performance of the company.

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

6 A: The results of an Incentive Compensation Survey of the 24 Western States taken by the
7 Garrett Group in 2007, and updated in 2009, 2011, and 2015 (attached as Exhibit MG-3),
8 shows that a clear majority of the states follow the financial-performance rule, in which
9 incentive payments associated with financial performance are excluded from rates.
10 Some states disallow incentive pay using other criteria. None of the jurisdictions
11 surveyed allow full recovery of incentive compensation through rates as a general rule.
12 A summary of the results of the Incentive Compensation Survey of the 24 Western
13 States is attached as Exhibit MG-3.

14
15 **Q: IN YOUR EXPERIENCE, WHEN REGULATORS EXCLUDE THE PORTION**
16 **OF A UTILITY'S INCENTIVE PLAN TIED TO FINANCIAL PERFORMANCE**
17 **MEASURES, DOES THE UTILITY STOP OFFERING INCENTIVE**
18 **COMPENSATION TO HELP ACHIEVE ITS FINANCIAL GOALS?**

19 No. Even though regulators generally disallow incentive compensation tied to financial
20 performance for ratemaking purposes, utilities continue to include financial performance
21 as a key component of their plans. In my opinion, utilities continue to tie incentive
22 payments to financial performance because by doing so they achieve the primary
23 objective of the incentive plans: to increase corporate earnings and, thereby, earnings per
24 share (EPS). However, since the utility retains the increased earnings these plans help

1 achieve, payments for the plans should be made from a portion of these increased
2 earnings. Thus, ratepayers need not subsidize properly designed incentive compensation
3 plans.

4
5 **Q: PLEASE ADDRESS THE ASSERTION THAT INCENTIVE PLANS SHOULD**
6 **BE INCLUDED IN RATES BECAUSE THEY ARE PART OF A TOTAL**
7 **COMPENSATION PACKAGE THAT IS COMPARABLE WITH THE**
8 **COMPENSATION PAID BY OTHER UTILITIES AND ARE NEEDED TO**
9 **ATTRACT AND RETAIN QUALIFIED PERSONNEL?**

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

20 The other common problem with the Company's "total compensation package"
21 argument is that when an incentive payment is based on achieving financial performance
22 goals there should be a financial benefit to the company that comes from achieving these

1 goals. This financial benefit should provide ample additional funds from which to make
2 the incentive payments. If not, the plan was poorly conceived. Thus, a utility is not
3 placed at a competitive disadvantage when incentive payments tied to financial
4 performance are not collected through rates, because the funding for these payments
5 should come out of the additional earnings the incentive plans help achieve.
6

7 **Q: WHY IS THE DISTINCTION BETWEEN FINANCIAL PERFORMANCE**
8 **MEASURES AND OPERATIONAL MEASURES AN IMPORTANT**
9 **DISTINCTION FOR INCENTIVE COMPENSATION ANALYSIS?**

10 A: When incentive compensation payments are based on financial performance measures,
11 the compensation agreement between shareholders and employees could be loosely
12 stated in this manner: "if you will help increase shareholder earnings, we will pay you a
13 bonus." The intended beneficiaries to this agreement are the shareholders and the
14 employees. Ratepayers have no stake in this agreement; therefore, they should bear none
15 of the costs that result from such an agreement. If, instead, the agreement were stated in
16 this manner: "if you will help increase reliability and quality of service to the customers,
17 we will pay you a bonus," then, ratepayers would have a stake in the agreement, and
18 could share in a portion of the costs. However, so long as some portion of the incentive
19 plan is designed to increase earnings, that portion of the plan should be funded out of the
20 increased earnings the plan helps produce.
21

1 **Q: ARE EMPIRE'S INCENTIVE PAYMENTS ALSO BASED ON OPERATIONAL**
2 **MEASURES?**

3 A: Yes.

4
5 **Q: WHAT ARE YOU RECOMMENDING FOR THE PORTION OF THE**
6 **INCENTIVE PLANS TIED TO OPERATIONAL MEASURES?**

7 A: I am recommending that all of the costs associated with operational measures be
8 disallowed as well. In my opinion, the incentive plan costs tied to operational measures,
9 such as safety, reliability and customer satisfaction should be disallowed because the
10 Company has performed poorly in these areas in recent years. Empire's JD Power
11 Customer Satisfaction ratings were far below average in 2016. The Company's
12 Reliability Scorecard filed annually with the Commission was also poor in 2016.

13
14 **Q: WHAT IS THE RELIABILITY SCORECARD?**

15 A: The OCC relies upon two basic gauges of electric service reliability – System Average
16 Interruption Frequency Index (“SAIFI”) and System Average Interruption Duration Index
17 (“SAIDI”). SAIFI is the average number of sustained interruptions of five minutes or more
18 per consumer. It is the ratio of the annual number of interruptions to the number of
19 consumers. SAIDI is the average duration of interruptions per consumers during the year. It
20 is the ratio of the annual duration of sustained interruptions to the number of consumers.¹¹

21

¹¹Oklahoma Corporation Commission Regulated Electric Utilities 2016 Reliability Scorecard May 1, 2016.

1 **Q: WHAT WERE THE RESULTS FOR EMPIRE IN THE 2016 REPORT?**

2 A: Empire's SAIFI scores were the worst in the state. On average, Empire's customers
3 experienced 2.5 outages per customer in 2015. This was 2½ times the state average of 1
4 outage per customer per year. The Empire SAIFI results compared to the rest of the
5 regulated utilities in Oklahoma can be seen at page 5 of the 2016 Reliability Scorecard,
6 attached as Exhibit MG-4.

7
8 **Q: WHAT ARE YOU RECOMMENDING WITH RESPECT TO THE COMPANY'S**
9 **INCENTIVE EXPENSE?**

10 A: I am recommending that 100% of the short-term annual incentive plan costs be excluded
11 from rates. This recommendation is based on the recognition that all incentive plan costs
12 tied to financial performance should be disallowed and incentive plan costs tied to
13 operational measures such as safety, reliability and customer satisfaction should only be
14 allowed if the utility performs well in these areas.

15
16 **Q: HAS THIS COMMISSION ADDRESSED RECOVERY OF INCENTIVE**
17 **COMPENSATION PAYMENTS IN PAST ORDERS?**

18 A: Yes. In its order in PUD 91-1190, at page 145, this Commission addressed ONG's
19 Gainshare Plan and the Executive Stock Performance Plan and disallowed the entire cost
20 of both plans, finding that the incentive plans were designed to increase corporate
21 earnings. In PUD 04-610, the ALJ recommended, and the Commission ordered, the

1 disallowance of the entire cost of QNG's incentive compensation payments. The ALJ
2 made the following recommendation:

3 The ALJ finds that incentive compensation should be disallowed from
4 inclusion in the rates paid by Oklahoma Natural's ratepayers. Incentive
5 compensation is typically tied to the attainment of certain financial goals,
6 efficiencies in operations or similar criteria, which create additional
7 income to the company, cost savings or other financial benefit. The ALJ
8 concurs with the argument of the Staff and AG that a well-designed
9 incentive compensation plan will generate resources from which to pay
10 the incentives to the employees. Therefore, the ALJ recommends
11 adoption of the Staff's recommended disallowance in the amount of
12 \$2,671,985.
13

14 In PSO's 2006 rate case, PUD 200600285, the Commission disallowed 50% of
15 AEP/PSO's annual incentive expense.¹²

16 The Commission finds that 50% of PSO's incentive costs should be excluded
17 for ratemaking purposes, as recommended by OIEC. The amount of those
18 incentive costs is \$3,454,217 as referenced in HE-17 at page 16 of 24, OIEC
19 Adjustment No. H-4.
20

21 In PSO's 2008 rate case, PUD 200800144, the Commission again disallowed 50% of
22 AEP/PSO's annual incentive plan.¹³

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

30 In PSO's 2015 rate case, PUD 201500208, the Commission again disallowed 50% of
31 AEP/PSO's annual incentive plan.¹⁴

¹² See Final Order in Cause No. PUD 200600285.

¹³ See Final Order in Cause No. PUD 200800144.

¹⁴ See Final Order in Cause No. PUD 201500208 at page 161 of attached ALJ Report.

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

8 In OG&E's 2005 rate case, PUD 200500151, the Commission's final order disallowed
9 60% of the Teamshare expense.

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

14 **Q: WHAT IS THE AMOUNT OF THIS ADJUSTMENT?**

15 **A:** This adjustment can be seen at Exhibit MG-2. The amount of this adjustment is \$49,048
16 for incentive pay and related payroll taxes.

III. B. (2) LONG-TERM INCENTIVE PLAN ADJUSTMENT

17 **Q: WHAT HAS EMPIRE PROPOSED WITH RESPECT TO THE RECOVERY OF**
18 **EXECUTIVE INCENTIVE PLAN?**

19 **A:** The Company is proposing to include \$37,574¹⁵ in rates for its long-term incentive plan.
20

21 **Q: WHAT TYPES OF LONG-TERM INCENTIVES ARE PROVIDED TO**
22 **EXECUTIVES AT EMPIRE?**

¹⁵ See Exhibit MG 2.3.

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, the ALJ
20 finds that an appropriately designed executive incentive compensation
21 will generate revenues or cost savings equivalent to the compensation
22 paid. Therefore, the ALJ finds that incentive compensation provides a
23 benefit to the shareholders rather than to the ratepayers. It is therefore the
24 recommendation of the ALJ that the Executive Compensation incentives
25 adjustment proposed by 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.¹⁶

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.¹⁷

24 In PSO's 2015 rate case, PUD 201500208, the Commission again disallowed 100% of
25 the utility's long-term incentive costs.¹⁸

26 With regard to long-term incentive compensation, the ALJ finds that the
27 recommendation of the Staff, AG, and OIEC to disallow 100% of long-
28 term incentive compensation is reasonable and should be adopted by the
29 Commission. The performance measures that result in the payment of
30 long-term incentive compensation are financial goals that benefit
31 shareholders.

¹⁶ See Final Order in Cause No. PUD 200600285 at page 145.

¹⁷ Order No. 564437 in Cause No. PUD 200800144 at page 21.

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

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

7

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

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

17 Further, when utilities, such as Empire, compete with other utilities for qualified
18 executives, and the executive incentive compensation plans of those other utilities are
19 not being recovered through rates, Empire is not placed in a competitive disadvantage
20 when its executive incentive compensation is excluded as well. Since most states
21 exclude long-term incentive pay as a matter of course and most other states exclude
22 long-term incentives as a practical matter, Empire would actually be given an unfair

¹⁸ See Final Order in Cause No. PUD 201500208 at page 162 of attached ALJ Report.
Responsive Testimony of Mark E. Garrett
Cause No. PUD 201600468

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

6 Therefore the Commission accepts BCP's and SNHG's
7 recommendations to disallow recovery of expenses associated with
8 LTIP. Both parties provide a valid argument that this type of
9 incentive plan is mainly for the benefit of shareholders. Further,
10 both BCP and SNHG provide examples of numerous other
11 jurisdictions that do not allow the recovery of these costs and,
12 therefore, disallowance in this instance would not place NPC in a
13 competitive disadvantage.¹⁹ (Emphasis added).

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

16 **A:** For the reasons outlined above, and based upon prior Commission orders, I am
17 recommending that 100% of the Company's long-term incentive expense. This
18 adjustment can be seen at Exhibit MG-2. The amount of this adjustment is \$(37,574).

III. B. (3) NON-QUALIFIED SUPPLEMENTAL EMPLOYEE RETIREMENT PLANS

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

20 **A:** The Company provides supplemental retirement plan benefits to certain highly-
21 compensated individuals at the Company. These supplemental retirement plans for highly-
22 compensated individuals are provided because benefits under the general retirement plans
23 are subject to limitations under the Internal Revenue Code. Benefits payable under these

1 supplemental plans are typically equivalent to the amounts that would have been paid but
2 for the limitations imposed by the Code. In general, the limitations imposed by the Code
3 allow for the computation of benefits on annual compensation levels of up to \$265,000 for
4 2016. Retirement benefits on compensation levels in excess of annual compensation limits
5 are paid through supplemental plans. Thus, supplemental retirement plans for highly
6 compensated employees are designed to provide benefits in addition to the benefits
7 provided under the general pension plans of the company. These plans are referred to as
8 *non-qualified* plans because they do not qualify as a deductible tax expense under the code.
9

10 **Q: WHAT DO YOU RECOMMEND WITH RESPECT TO SUPPLEMENTAL**
11 **EXECUTIVE RETIREMENT COSTS?**

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

¹⁹ See Final Order in Docket 08-12002 at paragraph 549.

1 Many regulators are inclined to exclude executive bonuses, incentive compensation and
2 supplemental benefits from utility rates, understanding that these costs would be better
3 borne by the utility shareholders.

4
5 **Q: HOW HAS SERP EXPENSE BEEN TREATED IN OTHER JURISDICTIONS**
6 **WHERE YOU HAVE TESTIFIED ON THE ISSUE?**

7 **A:** SERP expenses have been disallowed as follows:

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

10 In Oklahoma, the Commission disallowed 100% of AEP/PSO's SERP expense in
11 PSO's 2006 rate case, Cause No. PUD 200600285. Again, in PSO's 2008 rate case, Cause
12 No. PUD 200800144, and in PSO's 2015 rate case, Cause No. 201500208 the Commission
13 disallowed 100% of the Company's SERP expense.

14 In Nevada, the Commission disallowed SERP expense in Docket Nos. 01-10001,
15 03-10001, 06-11022, 08-12002, and 11-06006. In Arkansas, the Commission disallowed
16 SERP expense in Entergy Arkansas's last litigated rate case in that state, Docket No. 13-
17 028-U. The Commission agreed that shareholders, not ratepayers, should pay for the
18 cost of Entergy Arkansas' Supplemental Executive Retirement Plans. In Commission
19 Order No. 21 in that Docket, the Arkansas Commission determined that SERP expenses
20 are not necessary to provide utility service, but rather are discretionary costs
21 implemented by Entergy Arkansas that should be disallowed.

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

2 A: This adjustment can be seen at Exhibit MG-2. The impact of this adjustment is \$(2,061).

III. B. (4) 6-MONTH UPDATE TO PAYROLL EXPENSE

3 **Q: PLEASE DESCRIBE EMPIRE'S PAYROLL ADJUSTMENT.**

4 A: Empire annualizes payroll at test year end and then adds two additional adjustments to
5 increase the expense level: (1) the first adjustment increases payroll expense for future
6 pay raises and (2) the second adjustment increases payroll expense for unfilled positions.

7
8 **Q: DO YOU AGREE WITH EMPIRE'S PAYROLL EXPENSE ADJUSTMENTS?**

9 A: No. First, Empire provided no testimony to support these adjustments. Further, the two
10 adjustments proposed by Empire – for future pay raises and unfilled positions – are both
11 improper adjustments. With respect to future pay raises, these are not allowed for
12 ratemaking purposes. Pay raises that occur during the test year are captured and
13 quantified in the payroll annualization. It is improper then to add additional pay raises
14 after the test period. With respect to unfilled positions, this adjustment is always
15 improper. Unfilled positions do not represent actual expenditures of the utility and
16 cannot be included in rates.

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

19 A: I am proposing to reverse the two improper adjustments proposed by the Company for
20 (1) future pay raises and (2) unfilled positions.

1

2 **Q: WHAT IS THE IMPACT OF THIS ADJUSTMENT?**

3 A: This adjustment would reverse the two adjustments proposed by the Company and the
4 payroll tax expense associated with these adjustments. The adjustments are set forth
5 below and can be seen at Exhibit MG-2.

Description of Adjustment	Ref	Total Company Amount	Oklahoma Amount
Reverse Future Pay Raises	OK Rate Model	\$1,829,844	
Reverse Unfilled Positions	OK Rate Model	\$1,543,956	
Total		\$3,373,800	
Expense Ratio	OK Rate Model	74.63%	
Total Payroll Expense Adjustment		\$2,517,866	\$(72,205)
Payroll Tax Adjustment			\$(4,693)

III. B. (5) 6-MONTH UPDATE TO REVENUES

6 **Q: ARE THERE ANY OTHER 6-MONTH UPDATE ADJUSTMENTS NEEDED?**

7 A: Yes. Empire provided updated revenues adjusted for customer growth through
8 December 31, 2016 in response to AG 3-3. The adjustment needed to update revenues is
9 \$78,817 and can be seen at Exhibit MG-2.6.

10 **III. C. DEPRECIATION EXPENSE**

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

12 A: OIEC witness Mr. David Garrett proposes several changes to the Company's
13 depreciation study resulting in new proposed depreciation rates for many of the

1 Company's plant accounts. The impact of his adjustments on the revenue requirement
2 of Empire is a reduction in depreciation expense of \$(439,856).

3 **III. D. COST OF CAPITAL**

4 **Q: WHAT IS THE IMPACT OF OIEC'S COST OF CAPITAL**
5 **RECOMMENDATIONS?**

6 A: Mr. David Garrett addresses cost of capital issues. With respect to cost of capital, he
7 recommends a Return on Equity ("ROE") of 9.0%. The impact of his recommended
8 ROE on the Oklahoma revenue requirement is a reduction of \$(396,953).

9
10 **III. E. UNSUPPORTED PLANT ADDITIONS**

11 **Q: WHAT IS EMPIRE'S REQUEST REGARDING PLANT ADDITIONS?**

12 A: At page 6 of his testimony, Mr. Owens identifies \$669.5M of plant additions added since
13 the Company's last rate case in Oklahoma, which Empire seeks cost recovery for in this
14 rate proceeding. Empire, however, only provides testimony in support of \$304M of
15 these additions. Specifically, Empire provides limited testimony in support of its
16 environmental upgrades at Asbury and Riverton 12, but provides virtually NO testimony
17 in support of the remaining additions in the amount of \$365.5M, which is about \$10.1M
18 to the Oklahoma jurisdiction.

19
20 **Q: HAS THE COMMISSION BEEN PROVIDED WITH SUFFICIENT EVIDENCE**
21 **TO DETERMINE WHETHER THESE PLANT ADDITIONS ARE PRUDENT**

1 AND WHETHER THE COSTS ASSOCIATED THEREWITH ARE *JUST AND*
 2 *REASONABLE?*

3 A: No.

5 Q: WHAT PLANT HAS BEEN ADDED TO RATE BASE WITHOUT ADEQUATE
 6 TESTIMONY TO SUPPORT IT?

7 A: The table below shows the projects for which Empire provided no testimony to support
 8 their inclusion in customers' rates. The table also includes the Asbury and Riverton 12
 9 projects which had very little testimony or economic analysis supporting the prudence of
 10 these projects.

Table 2: Capital Additions with No Testimony or Inadequate Support		
	Plant with No Support	Total Co. Amount
1	Ongoing Integrity Capital Expenditures (Poles, Station Equipment, Overhead Conductors, Transformer, etc.)	\$302.4
2	Project Overhaul (PeopleSoft, PowerPlant, SharePoint, Work Management systems)	\$20.6
3	Iatan II and Plum Point True-up	\$20.3
4	Kodiak Service Center	\$16.4
5	Miscellaneous Additions	\$5.8
6	Total Plant with No Support	\$365.5
Plant with Limited (Insufficient) Support		
7	Asbury Air Quality Control System	\$122
8	Riverton 12 Combined Cycle Conversion Project	\$182
9	Total Plant with Insufficient Support	\$304
10	Total Plant with No or Insufficient Support	\$669.5

1 **Q: WHO BEARS THE BURDEN OF PROOF REGARDING EMPIRE'S**
2 **RECOVERY OF THESE PLANT ADDITIONS IN RATES?**

3 A. My understanding is that the Applicant, Empire in this instance, has the burden of
4 proving the reasonableness of the rates it seeks. In addition, a public utility's rates must
5 be reasonable and just and the lowest reasonable rates for ratepayers. I do not believe
6 that Empire has met its burden in this instance with respect to recovery of the above
7 Plant additions.

8
9 **Q: WHAT IS YOUR RECOMMENDATION REGARDING EMPIRE'S RECOVERY**
10 **OF THESE CAPITAL ADDITIONS?**

11 A: Empire has requested an unprecedented 46.26% increase in base rates with virtually no
12 support for the majority of the asset additions behind this increase, and insufficient
13 support for the remaining assets causing the increase – Asbury and Riverton 12. The
14 Commission would be justified in rejecting Empire's entire requested rate increase based
15 on the fact that Empire failed to provide adequate support for the asset additions causing
16 the increase. At a minimum, the Commission should reject all of the requested increase
17 related to the \$365.5 million of unsupported plant in the table above, along with all of
18 the costs associated with that plant, such as depreciation, property tax, O&M expenses
19 and administrative costs. The Company would be eligible to resubmit these costs for
20 inclusion in rates in the Company's next rate case proceeding.

21
22

1 **III. F. RATE CASE EXPENSES**

2 **Q: DO YOU HAVE ANY FURTHER RECOMMENDATIONS?**

3 A: Yes. I have a recommendation regarding the recovery of rate case expenses. In my
4 opinion, utilities should only be allowed to recover rate case expenses in proportion to
5 the rate increase granted by the Commission compared to the amount of rate increase
6 requested by the utility in its rate case application. This treatment was recently
7 articulated by the Missouri Public Service Commission,²⁰ as follows:

8 164. Awarding a utility all of its incurred rate case expenses could
9 provide that utility with a significant financial advantage over other
10 participants in the rate case process, who may be constrained by
11 budgetary and other financial restrictions. Such a practice does not
12 encourage reasonable levels of cost containment in the utility's rate case
13 expense decisions.

14 165. An incentive for a utility to limit its rate case expense is to tie a
15 utility's percentage recovery of rate case expense to the percentage of its
16 rate increase request that the Commission finds just and reasonable. Use
17 of this approach would directly tie a utility's recovery of rate case
18 expense to both the reasonableness of its issue positions and the dollar
19 value sought from customers in a rate case.

20 In my view, it is appropriate from a policy perspective to tie a utility's percentage
21 recovery of rate case expense to the percentage of its rate increase actually awarded.
22 This provides incentives for a utility to control its rate case costs and to ensure the
23 reasonableness of its issue positions. Moreover, limiting a utility's rate case expense
24 recovery levels the playing field between the company and its customers.

²⁰ *In the Matter of Kansas City Power & Light*, File No. ER-2014-0730 et.al., Order dated September 2, 2015.

IV. CONCLUSION

1 **Q: WHAT IS YOUR RECOMMENDATION IN THIS CASE?**

2 A: The Commission could authorize an environmental compliance rider for Empire's
3 recovery of the capital costs of the two projects, Asbury and Riverton 12, similar to what
4 was authorized in Kansas by the Kansas Corporation Commission, but nothing more. If
5 the Commission is inclined to reject that approach and instead, adopt a traditional
6 approach to this case, it should adopt all of the adjustments outlined above to the
7 Company's pro forma revenue requirement, including an adjustment to reject recovery in
8 this proceeding of the unsupported plant in the table above, along with all of the costs
9 associated with that plant, such as depreciation, property tax, O&M expenses and
10 administrative costs.

11
12 **Q: DO YOU HAVE ANY FURTHER ADJUSTMENTS TO THE COMPANY'S
13 REVENUE REQUIREMENT?**

14 A: No, not at this time. However, my testimony does not address every potential revenue
15 requirement issue and I reserve the right to supplement my recommendations following
16 my review of the other parties' responsive testimony and the Company's rebuttal
17 testimony. The fact that I do not express an opinion on a particular issue is not to be
18 interpreted as agreement with the Company's position on that issue.

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

21 A: Yes, it does.

MARK E. GARRETT

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EDUCATION:

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

CREDENTIALS:

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

WORK HISTORY:

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

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

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

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

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

1. **Caesars Enterprise Service, LLC, 2016 (704B Exit Application)** – Participating as an expert witness on behalf of Caesars before the Nevada PUC. Sponsoring written and oral testimony in Caesar’s application to purchase energy and capacity from a provider other than Nevada Power.
2. **Southwestern Electric Power Company, 2016 (PUC Docket No. 46449)** – Participating as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s general rate case proceeding to provide testimony on various cost of service issues and on the utility’s revenue requirement.
3. **CenterPoint Texas, 2016 (Docket No. 10567)** – Participating as an expert witness on behalf of City of Houston before the Texas Railroad Commission in CenterPoint’s general rate case application, sponsoring testimony to address the utility’s overall revenue requirement and various rate design proposals.
4. **Entergy Texas, Inc., 2016 (Docket No. 46357)** – Participating as an expert witness on behalf Cities Served by Applicant before the Texas PUC in ETI’s application to amend its Transmission Cost Recovery Factor.
5. **Anchorage Municipal Light and Power, 2016 (Docket No. U-16-060)** – Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P’s acquired interest in the Beluga River Unit gas field with ratepayer funds.
6. **Arizona Public Service Company, 2016 (Docket No. E-01345A-16-0036)** – Participating as an expert witness before the Arizona Corporation Commission in APS’s General Rate Case application on behalf of Energy Freedom Coalition of America to provide written and oral testimony to address various revenue requirement issues.
7. **Oklahoma Gas & Electric Co. (Arkansas), 2016 (Docket No. 16-052-U)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”)¹ before the Arkansas Public Service Commission in OQ&E’s general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.
8. **Sierra Pacific Power Company, 2016 (Docket No. 16-06006)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers² before the Nevada PUC in SPPC’s general rate case proceeding. Sponsored testimony on various revenue requirement, depreciation, and rate design issues.
9. **Tucson Electric Power, 2016 (Docket No. E-01933A-15-0322)** – Participating as an expert witness before the Arizona Corporation Commission in TEP’s General Rate Case application, on behalf of Energy Freedom Coalition of America providing written and oral testimony to address the utility’s cost of service study and rate design proposals.
10. **Texas Gas Service, 2016 (Docket No. 10506)** – Participated as an expert witness on behalf of El Paso before the Texas Railroad Commission in TGS’s General Rate Case application, sponsoring

¹ ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

² The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

testimony to address the utility's overall revenue requirement and various rate design proposals.

11. **Texas Gas Service, 2016 (Docket No. 10488)** – Participated as an expert witness on behalf of South Jefferson County Service Area (“SJCSA”) before the Texas Railroad Commission in TGS’s General Rate Case application, sponsoring testimony to address the utility’s overall revenue requirement and various rate design proposals.
12. **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.
13. **Oklahoma Gas & Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of The Alliance for Solar Choice (“TASC”) before the Oklahoma Corporation Commission to address OG&E’s proposed Distributed Generation (“DG”) rates for solar DG customers.
14. **Anchorage Municipal Light and Power, 2016 (Docket No. U-13-097)** – Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on rates and tariffs proposed for customer-owned combined heat and power plant generation.
15. **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.
16. **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.
17. **Nevada Power Company, 2015 (Docket No. 15-07004)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”)³ 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.
18. **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”)⁴ before the Arkansas Public Service Commission in OG&E’s Act 310 application to implement a rider to recover environmental compliance costs.
19. **MGM Resorts, LLC, 2015 (Docket No. 15-05017)** – Participated as an expert witness on behalf of the MGM Resorts, LLC before the Nevada PUC. Sponsoring written and oral testimony in MGM’s application to purchase energy and capacity from a provider other than Nevada Power.
20. **Entergy Arkansas, 2015 (Docket No. 15-015-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”) an intervener group that includes the University of

³ The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.

⁴ ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

21. **Public Service Company of Oklahoma, 2015 (Cause No. PUD 201500208)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.
22. **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.
23. **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.
24. **Oklahoma Gas and Electric Co., 2014 (Cause No. PUD 201400229)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC")⁵ 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.
25. **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.
26. **Anchorage Municipal Light and Power, 2014 (Docket No. U-13-184)** – Participated as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on various revenue requirement and cost of service issues.
27. **Public Service Company of Oklahoma, 2014 (Cause No. PUD 201300217)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.
28. **Entergy Texas Inc., 2013 (PUC Docket No. 41791)** – Participated as an expert witness on behalf of the Cities⁶ in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.
29. **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.
30. **Entergy Arkansas, 2013 (Docket No. 13-028-U)** – Participated as an expert witness on behalf of the

⁵ OIEC is an association of approximately 25 large commercial and industrial customers in Oklahoma.

⁶ 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.

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.

31. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers⁷ 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.
32. **Gulf Power Company, 2013 (Docket No. 130140-ED)** – 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.
33. **Public Service Company of Oklahoma, 2013 (Cause No. PUD 201200054)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission (“OCC”) to provide testimony in PSO’s application seeking Commission approval of its settlement agreement with EPA.
34. **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.
35. **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.
36. **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.
37. **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
38. **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.
39. **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.
40. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participated as an expert witness on behalf of the OIEC before the OCC in ONG’s Performance Based Rate (“PBR”) application seeking Commission approval of a requested rate increase based upon formula results for

⁷ The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

2011.

41. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility services to the university.
42. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.
43. **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.
44. **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.
45. **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.
46. **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.
47. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
48. **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.
49. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking to include retiree medical expense in the Company's pension tracker mechanism.
50. **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.
51. **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.

52. **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”)⁸ before the Arkansas Public Service Commission in OG&E’s general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.
53. **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.
54. **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.
55. **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.
56. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities (“ATM”) before the Texas PUC in TMNP’s general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
57. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147)** – Participated as an expert witness on behalf of the Alliance of Xcel Municipalities (“AXM”) in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.
58. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participated as an expert witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E’s 220MW self-build wind project.
59. **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.
60. **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.
61. **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.
62. **Entergy Texas Inc., 2010 (PUC Docket No. 37744)** – Participated as an expert witness on behalf of

⁸ NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

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.

63. **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.
64. **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.
65. **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.
66. **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.
67. **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.
68. **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.
69. **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.
70. **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.
71. **Texas-New Mexico Power Co., 2008 (Docket 36025)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
72. **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.
73. **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.

74. **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.
75. **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.
76. **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.
77. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO₂ allowances.
78. **Rocky Mountain Power, 2008 (Docket No. 07-035-93)** – Participated as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp’s general rate case to provide testimony on various revenue requirement issues.
79. **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.
80. **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.
81. **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.
82. **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.
83. **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.
84. **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.

85. **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.
86. **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.
87. **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.
88. **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.
89. **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.
90. **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.
91. **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.
92. **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.
93. **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.
94. **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.
95. **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.

96. **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.
97. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participated as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.'s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.'s proposed increase in depreciation rates associated with increased negative salvage value calculations.
98. **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.
99. **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:
100. **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.
101. **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.
102. **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.
103. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSQ's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
104. **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.
105. **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.

106. **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.
107. **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.
108. **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.
109. **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.
110. **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.
111. **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.
112. **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.
113. **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.
114. **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.
115. **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.

116. **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.
117. **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.
118. **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.
119. **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.
120. **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.
121. **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.
122. **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.
123. **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.
124. **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.

125. **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.
126. **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.
127. **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.
128. **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.
129. **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.
130. **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.
131. **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.
132. **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.
133. **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.
134. **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.

135. **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.
136. **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.
137. **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.

EMPIRE DISTRICT ELECTRIC COMPANY
OIEC WORKPAPERS - CAPITAL COST RECOVERY FOR ASBURY AND RIVERTON 12
 Test Year Ended June 30, 2016
 Cause No. PUD 201600468

Line	Description	Asbury	Riverton 12	Total	Oklahoma
					2.75%
1	Plant in Service	\$ 122,292,465	\$ 181,640,749	\$ 303,933,214	\$ 8,364,242
2	Accumulated Depreciation	(11,476,271)	(2,344,710)	(13,820,981)	(380,353)
3	ADIT	(22,144,455)	(34,641,953)	(56,786,408)	(1,562,762)
4	Total	\$ 88,671,739	\$ 144,654,086	\$ 233,325,825	\$ 6,421,127
5	Pre-Tax Rate Of Return				<u>9.79%</u>
6	Return				\$ 628,406
7	Depreciation Expense	\$ 2,283,425	\$ 4,104,607	\$ 6,388,032	\$ 175,799
8	ECP Rider Revenues - Year 1				\$ 804,205

Source: AG-EDE-7

EMPIRE DISTRICT ELECTRIC COMPANY
OEIC WORKPAPERS - ADJUSTMENTS TO UPDATE RATE BASE TO 6-MONTH CUTOFF
Test Year Ended June 30, 2016
Docket No. PUD 201600468

Line	Description	Reference	Rate Base Adjustment	%	Amounts
6-Month Update Adjustments					
1	Plant in Service	AG DR 2.9 - Supp	\$ 930,891	10.688%	\$ 99,489
2	Accumulated Depreciation	AG DR 2.9 - Supp	\$ (1,258,151)	10.688%	\$ (134,465)
3	Materials and Supplies	AG DR 2.10-Supp	\$ (38,942)	10.688%	\$ (4,162)
4	Prepayments	AG DR 2.19-Supp	\$ 22,003	10.688%	\$ 2,352
5	Accumulated Deferred Income Tax	AG DR 2.21-Supp	\$ (688,836)	10.688%	\$ (73,619)
6	Customer Deposits	AG DR 2.11	\$ (2,342)	10.688%	\$ (250)
7	Total OIEC Rate Base Adjustment	AG DR 2.22 - Supp	<u>\$ (1,035,377)</u>		<u>\$ (110,656)</u>
8	OIEC 6-Month Update Adjustment		<u>\$ (1,035,377)</u>		<u>\$ (110,656)</u>

EMPIRE DISTRICT ELECTRIC COMPANY
OIEC WORKPAPERS - SHORT TERM INCENTIVES ADJUSTMENT
Test Year Ending JUNE 30, 2016
Cause No. PUD 201600468

Line No.	Description	Reference	Amount	Expense Ratio	Okla. Juris	OIEC Adjustment
1	Total Short Term Incentive	OK Rate Model	\$ 2,163,196	74.24%	2.87%	<u>\$ 46,054</u>
2	OIEC Adjustment to Remove Short Term Incentives					\$ (46,054)
3	Payroll Tax Rate					0.065
4	OIEC Adjustment to Remove Payroll Tax on Short Term Incentives					<u>\$ (2,994)</u>
5	OIEC Total Adjustment for Short Term Incentives and Related Payroll Taxes					<u>\$ (49,048)</u>

EMPIRE DISTRICT ELECTRIC COMPANY
OIEC WORKPAPERS - LONG TERM INCENTIVES ADJUSTMENT
Test Year Ending JUNE 30, 2016
Cause No. PUD 201600468

Line No.	Description	Reference	Amount	Expense Ratio	Okla. Juris	OIEC Adjustment
1	Total Long Term Incentives	OK Rate Model	\$ 1,764,889	74.24%	2.87%	<u>\$ 37,574</u>
2	OIEC Adjustment to Remove Long Term Incentives					<u>\$ (37,574)</u>

EMPIRE DISTRICT ELECTRIC COMPANY
OIEC WORKPAPERS - ADJUSTMENT TO SERP EXPENSE
Test Year Ending JUNE 30, 2016
Cause No. PUD 201600468

Line No.	Description	Ref.	Total
1	Supplemental Executive Retirement Plan Costs	OK Rate Model	\$ 96,791
2	Expense %		<u>74.24%</u>
3	SERP in Cost of Service		<u>\$ 71,854</u>
4	OIEC Adjustment to Remove SERP Expense		<u>\$ (71,854)</u>
5	Jurisdictional %		<u>2.87%</u>
6	OIEC Adjustment to Remove SERP Expense		<u><u>\$ (2,061)</u></u>

**EMPIRE DISTRICT ELECTRIC COMPANY
OIEC WORKPAPERS - ADJUSTMENT TO PAYROLL
Test Year Ended June 30, 2016
Cause No. PUD 201600468**

Line	Description	Reference	Amount	Okla Juris. %	Okla Amount
1	Reverse Future Pay Raises	OK Rate Model	\$ (1,829,844)		
2	Reverse Unfilled Positions	OK Rate Model	\$ (1,543,956)		
3	Total		<u>\$ (3,373,800)</u>		
4	Expense Ratio		74.63%		
			<u>\$ (2,517,867)</u>	2.87%	<u>\$ (72,205)</u>
		10			
5	Payroll Tax Rate		6.50%		
			<u>\$ (163,661)</u>	2.87%	<u>\$ (4,693)</u>

**EMPIRE DISTRICT ELECTRIC COMPANY
OIEC WORKPAPERS - ADJUSTMENT TO REVENUES
Test Year Ended June 30, 2016
Cause No. PUD 201600468**

Line No.	Description	Ref.	Adjustment
1	Revenue adjusted for Customer Growth at 6/30/2016		\$ 8,437,640
2	Revenue adjusted for Customer Growth at 12/31/2016	AG 3-3	\$ 8,516,457
3	OIEC Adjustment to update customer Growth to 12/31/2016		<u>\$ 78,817</u>

**EMPIRE DISTRICT ELECTRIC COMPANY
OIEC WORKPAPERS - COST OF CAPITAL
Test Year Ended June 30, 2016
Cause No. PUD 201600468**

<u>Test Year</u>							
1	Long-Term Debt	\$ 818,767,313	49.40%	5.30%	2.62%	1.00	2.618%
2	Common Equity	\$ 808,323,141	48.76%	9.90%	4.83%	1.63077	7.873%
3	Short-Term Debt	\$ 30,500,000	1.84%	0.62%	0.01%	1.00	0.011%
4	Total	\$ 1,657,590,454	100.00%		7.46%		10.502%
<u>Pro Forma</u>							
5	Long-Term Debt	\$ 818,767,313	50.32%	5.30%	2.67%	1.00	2.667%
6	Common Equity	\$ 808,323,141	49.68%	9.90%	4.92%	1.63077	8.020%
7	Short-Term Debt	\$ -	0.00%	0.62%	0.00%	1.00	0.000%
8	Total	\$ 1,627,090,454	100.00%		7.59%		10.688%
<u>OIEC</u>							
9	Long-Term Debt	\$ 818,767,313	49.40%	5.30%	2.62%	1.00	2.618%
10	Common Equity	\$ 808,323,141	48.76%	9.00%	4.39%	1.63077	7.157%
11	Short-Term Debt	\$ 30,500,000	1.84%	0.62%	0.01%	1.00	0.011%
12	Total	\$ 1,657,590,454	100.00%		7.02%		9.787%
<u>ECP Rider</u>							
13	Long-Term Debt	\$ 818,767,313	49.40%	5.30%	2.62%	1.00	2.618%
14	Common Equity	\$ 808,323,141	48.76%	9.00%	4.39%	1.63077	7.157%
15	Short-Term Debt	\$ 30,500,000	1.84%	0.62%	0.01%	1.00	0.011%
16	Total	\$ 1,657,590,454	100.00%		7.02%		9.787%

INCENTIVE SURVEY SUMMARY OF RESPONSESStates that follow the Financial-Performance Rule:**Arizona**

The Commission deals with incentive compensation plans on a case by case basis. Evaluation centers on the criteria of benefit to customers. This treatment tends to make long-term programs harder to justify, but the same criteria are used to evaluate all plans including those for executives. This treatment is set forth in the most recent Epcor Water rate case.¹ The current treatment represents a somewhat more liberalized approach compared to Arizona's former position of excluding all incentive compensation from rates.

A review of Commission decisions in cases since the 2001 Decision 64172 is provided in the testimony of staff witness Ralph C. Smith in Docket No. E-0134SA-16-0036 (pp.81-89). This review demonstrates that the Commission recognizes that financial goals primarily benefit the shareholder and operational goal can benefit the customer. The Commission accordingly shares the cost of short-term incentives equally between ratepayers and the shareholders. In Decision No. 71914 (September 30, 2010), in UNS Electric, Inc. rate case, Docket No. E-04204A-09-0206, the Commission stated at page 28 that:

We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area.

Arkansas

Excludes 100% of the long-term, equity-based plans. Short-term incentive plans are evaluated to determine if they are based on financial or operational measures. Operational-based plans are allowed. 50% of plans containing financial measures are disallowed. Any plans based solely on the discretion of the company are seen as having no direct benefit to ratepayers and are disallowed 100%. Settlements in recent cases have upheld this treatment.² Commission rulings on Incentive Compensation have remained generally consistent, excluding 100% of long-term plans and 50% of the portion of short-term plans that are financially based. This treatment has been qualified in recent cases based on differing plan structures. In the most recent contested Entergy rate case (Docket No. 13-028-U), 50% of all short-term incentive compensation was excluded because the plans included a financially-based multiplier.

¹Epcor 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.

²Entergy Arkansas, Docket No. 06-101-U, Order No. 10 and Docket No. 13-028-U, Order No. 21.

- California** The Commission has established precedence for evaluating plans based on who benefits from the plans goals, ratepayer or shareholders. In CPUC Decision 00-02-046, the Commission established that utilities could recover 50% of the regular employee's incentive compensation costs in rates. In the Southern California Edison litigated rate case Decision 09-03-025, the Commission decided that Edison's non-executive plans and 50% of the short-term executive plans would be funded in rates and that 100% of the executive long-term stock plans would be disallowed.³ In a recent case, A.10-07-007, staff recommended that, "customer funding should be limited to the portion of the incentive plan payments that are aligned with operational objective that provide customer benefits. This means that 70% of AIP be funded by shareholders, and 30% be funded by ratepayers." In the settlement, the Commission disallowed 50% of the plan's expense.
- Hawaii** Incentive compensation of all types is excluded from rates. The Commission upholds the position stated in Docket No. 6531 that incentives tied to company income and earnings benefit stockholders, not ratepayers. The Commission further stated, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service."⁴ Utilities in Hawaii no longer petition to have incentive compensation expense included in rates.
- Idaho** The Commission's policy for evaluating incentive compensation plans involves determining who benefits, the customer or the company. This treatment was refined in the Idaho Power rate case, IPC-E-08-10, for plans which benefit the customer but require a financial trigger to be paid. For these plans the Commission reduced the percentage allowed in rates. The Commission does not include executive compensation in rates.⁵
- Kansas** For officer level incentives plans, the financially-based portion is borne by the shareholders and the portion supporting operational goals is allowed in rates. Non-officer incentive compensation plans for workers are allowed in rates.⁶ The consumer advocacy branch, Citizens' Utility Ratepayer Board (CURB) has consistently recommended applying the same financial/operational criteria to non-officer plans as well. In the current KCPL rate case the company has

³ Southern California Edison (Application No. 07-11-011; Decision No. 09-03-025).

⁴ 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.

⁵ 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.

⁶ 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.

voluntarily excluded 100% of the performance-based plans and 50% of the short-term plans with an earnings-per-share qualifier. The Company also removed the earnings-per-share portion of their plan for all employees.

- Louisiana** Traditionally incentive compensation for upper level management and officers is excluded, while costs for lower level managers and employees are allowed. The criteria used to evaluate plan design consider whether the goals of each plan directly benefit ratepayers or shareholders. Stock based compensation plans at all levels are excluded.
- Minnesota** Minnesota continues to distinguish between incentive plans tied to financial triggers (such as a threshold ROE) and plans tied to criteria benefitting the ratepayer. Plans based on goals which benefit ratepayers are generally allowed in rates, but their costs are frequently capped at a percentage of base salaries such as 15% or 25%.⁷ Utilities are usually required to return to ratepayers any portion of incentive pay that was allowed into rates and is not subsequently paid out to employees. Executive and long-term IC measures are frequently more closely aligned with shareholder interests and thus are not usually allowed in rates.⁸
- Missouri** Plans are analyzed to determine who benefits. Plans that can show a direct benefit to customers and that are found to be prudent are allowed in rates. Plans that benefit shareholders are excluded. The Commission also allows only the amounts actually paid, not those accrued. The same criteria are used for executive plans and few are allowed.⁹
- Montana** Due to the low volume of litigated cases in the past 10 to 15 years in Montana, incentive compensation has not been an important issue before the Commission. However, the Commission tends to become more concerned by incentive plans that are tilted toward financial performance instead of operational goals.
- Nebraska** Nebraska does not have rules regarding incentive compensation and considers the issue on a case by case basis. In a 2007 rate case, NG-0041, the Commission disallowed 50%, directing that cost should follow benefit and stating, "However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to

⁷ 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.

⁸ 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.

⁹ 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.

bear the full cost of this benefit." The Commission also allowed in rates only the actual amounts paid. In NG-0060 the Commission disallowed the entire amount requested by SourceGas for cash incentives.

- Nevada** The Commission excludes 100% of the long-term plans and all short-term plan costs directly related to financial performance.¹⁰
- New Mexico** Incentive programs tied to measures that benefit ratepayers (such as operation and safety) are allowed in rates. Programs tied to the financial performance of the utility (e.g. stock price or ROE) are not allowed in rates. This standard is applied to all levels of utility employees and tends to eliminate the greater portion of executive plans.¹¹ Executive incentive plans receive more scrutiny as they are more likely to have financial measures. They can also be challenged if the overall percentage is out of line. One major utility in New Mexico no longer includes the compensation of its top 5 executives in rate applications.
- N. Dakota** In North Dakota, the general policy is the portion that relates to earnings of the shareholders is disallowed and the rest is included. In the past, the Commission has limited incentives to 15% of salary. The general approach is to determine if incentive compensation is reasonable and fair based on market analysis. Historically, executive incentive compensation is not allowed in rates, and is typically not sought by the company.
- Oklahoma** The Commission excludes incentive payments tied to financial performance. From a practical perspective this means that all long-term plans are excluded and some portion of the annual short-term cash plan are excluded. The Commission does not determine the precise portion of the annual plans tied to financial measures but instead excludes 50% of the annual plans. 100% of the long-term executive stock-based plans are excluded.¹²
- Oregon** The Commission's general policy is based on the idea that customers should not have to pay for incentive compensation based on financial goals such as rate of return. For short-term plans, the portion based on financial measures is excluded from rates. The only long-term plans are for officers, and 100% of officer incentives are excluded from rates.
- S. Dakota** South Dakota considers incentive compensation on a case by case basis. Their general policy is to evaluate each plan and disallow the portion based on financial performance indicators. This treatment is set forth in the recent case EL14-026 in which the order specifically excluded the amount "tied to the Company's financial results."¹³ Current treatment also includes disallowing both

¹⁰ See e.g., PUCN's final order in Docket 11-06006.

¹¹ See Docket 07-00077-UT.

¹² See e.g., AEP-PSO Cause Nos. PUD 06-285 and PUD 08-144; CP Cause No. PUD 05-151; and ONG Cause No. PUD 04-610.

¹³ 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

executive and non-executive management incentive compensation. Several utilities have whole incentive programs that hinge on whether or not the company earns a certain return. These financial prerequisites cause the whole plans to be excluded from rates.

Texas

The general rule is that incentive payments designed to improve the financial performance of the utility are excluded. For example, in PUC Docket No. 28840,¹⁴ the Commission disallowed sixty-six percent (66%) of AEP-Texas Central's test year incentive payments in the amount of \$4.2 million. This was the portion of the utility's incentive payments that were based on financial performance measures.¹⁵ Long-term stock incentives are strictly excluded. At the RRC, financial incentives are generally excluded and customer-related incentives are generally allowed in rates. Examples include: Atmos 9670, TGS 9988, and TGS 10506. In Docket 9670 both the executive and employee plans for Atmos Mid-Tex were found not to be just and reasonable because they, "advanced the interest of shareholders, and [are] driven by Company earnings." None of the costs of these programs were allowed in rates. In TGS Docket 9988, the RRC found 100% of long-term and 90% of short-term incentives expense should be excluded because these were the portions related to the financial performance of ONEOK Inc. In GUD 10506, the Commission split the STI costs 50/50; the Commission also excluded 100% of the LTI tied to financial performance and split the remaining LTI costs 50/50.

Utah

The Commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. Equity-based incentive compensation is excluded from rates.¹⁶

Washington

Incentive plans are evaluated on a case by case basis. Incentives tied to operational efficiency or other measures which benefit ratepayers are allowed in rates and incentives based on return on earnings or other measures that benefit the shareholders are disallowed.¹⁷

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."

¹⁴ *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).

¹⁵ 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.

¹⁶ 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.

¹⁷ See the Order in Pacific Power and Light Docket 061546.

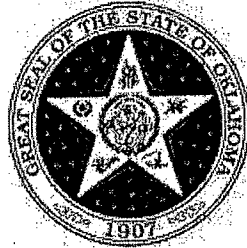
Wyoming Historically, employee incentive compensation plans are evaluated on a case by case basis, distinguishing between employee programs that benefit the ratepayer or the stockholders and requiring the benefitting party to pay. Executive incentive compensation plans are generally excluded from rates.

States that use another approach

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

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

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



OKLAHOMA CORPORATION COMMISSION

REGULATED ELECTRIC UTILITIES

2016 RELIABILITY SCORECARD

May 1, 2016

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1.0 Introduction

The annual Reliability Scorecard (“Scorecard”) is being presented in accordance with Oklahoma Corporation Commission (“OCC” or “Commission”) Electric Utility Rules as provided in OAC 165:35-25, Part 3, Reliability of Service and Reliability Program. The reliability of regulated electric utilities cannot be assessed without generally understanding how their dependability is measured. The OCC primarily relies upon two basic gauges of electric service reliability – System Average Interruption Frequency Index (“SAIFI”) and System Average Interruption Duration Index (“SAIDI”) – to gain insights regarding how consistently the state’s regulated electric utility systems are providing uninterrupted energy. SAIFI is the average number of sustained interruptions (five minutes or more of zero voltage per incident) per consumer during a year. It is the ratio of the annual number of interruptions to the number of consumers (Total number of sustained interruptions in a year / Total number of consumers). SAIDI is the average duration of interruptions per consumers during the year. It is the ratio of the annual duration of sustained interruptions to the number of consumers (Total duration of sustained interruptions in a year / Total number of consumers). If duration is specified in minutes, SAIDI is given as consumer minutes.

2.0 Summary

There are six electric utilities regulated by this Commission that reported reliability information contained in this report¹. These six utilities are Arkansas Valley Electric Cooperative Corp. (“Arkansas Valley”)², Canadian Valley Electric Cooperative, Inc. (“Canadian Valley”)³, The Empire District Electric Co. (“Empire”), Northeast Oklahoma Electric Cooperative, Inc. (“NOEC” or “Northeast Oklahoma”)⁴, Oklahoma Gas and Electric Co. (“OG&E”) and Public Service Company of Oklahoma (“PSO”). The SAIFI measure indicates that an Oklahoma customer being served by a regulated electric utility experienced an average of approximately 1.372 outages in 2015. The SAIDI measure indicates that customers served by Oklahoma’s regulated electric utilities were without power during 2015 for an average of approximately 155.02 minutes, or 2.584 hours.

3.0 Purpose

The purpose of this Scorecard, pursuant to OCC rule, OAC 165:35-25-24, is to present results of calculations that measure reliability of electric utility systems regulated by the Commission in the State of Oklahoma to allow for a comparison of service reliability performance measurements for those utilities. These calculations are based on customer counts, SAIFI, and SAIDI data. Pursuant to Commission rules, the utilities provided data for circuits that had the

¹ Rich Mountain Electric Cooperative and Southwest Arkansas Electric Cooperative are regulated by the Commission. However, both Companies have a small number of Oklahoma customers and Southwest Arkansas does not have reliability statistics separated for Oklahoma only customers, so the data for both companies has not been included.

² Annual figures for Arkansas Valley are not available for 2015 due to a mid-year change in the Company’s outage reporting software.

³ The reported figures for Canadian Valley are higher than usual in 2015 due to Western Farmers transmission outages early in the year.

⁴ The outage time associated with 5,296 outage hours attributable to NOEC’s wholesale power supplier (Grand River Dam Authority, “GRDA”) has not been removed from the Company’s calculations of SAIDI and SAIFI in 2015.

most outages during 2015 and preceding years. This Scorecard enables the Commission and others to monitor the performance/improvements of Oklahoma's Commission-regulated power utilities and trends in electric system reliability over time.

The following companies provided data pursuant to OAC 165:35-25:

Oklahoma Customers at Year-End					
Company	2011	2012	2013	2014	2015
Arkansas Valley	4,068	3,816	4,173	9,437	
Canadian Valley	24,009	24,182	24,387	24,547	24,676
Empire	6,639	6,673	6,690	6,694	6,687
NOEC	38,200	38,679	38,379	38,159	39,209
OGE	713,726	757,754	715,447	742,972	751,568
PSO	527,969	531,489	535,673	538,423	540,140

4.0 Definitions⁵

Distribution system: That network of electric wires and equipment that carries electric energy from substation to the customer's premises.⁶

Duration of interruption: The period (measured in seconds, minutes, hours, or days) from initiation of an interruption of service to a customer or other facility until service has been restored to that customer or facility. An interruption may require step-restoration tracking to provide reliable index calculation.

Major event: A disastrous event exceeding design limits of the electric power system and generally characterized, depending upon the utility, by

- a) Extensive damage to the electric power system,
- b) More than a specified percentage of customers simultaneously out of service,
- c) Service restoration times longer than specified.

Causes of major events can include such things as extreme weather, for example, a severe ice storm or tornado, or even an earthquake. As defined in Commission rules at OAC 165:35-25-13, a "major event" includes "situations where there is a loss of service to 10 percent or more of the customers in a region, and where full restoration of all affected customers requires more than 24 hours from the beginning of the event."

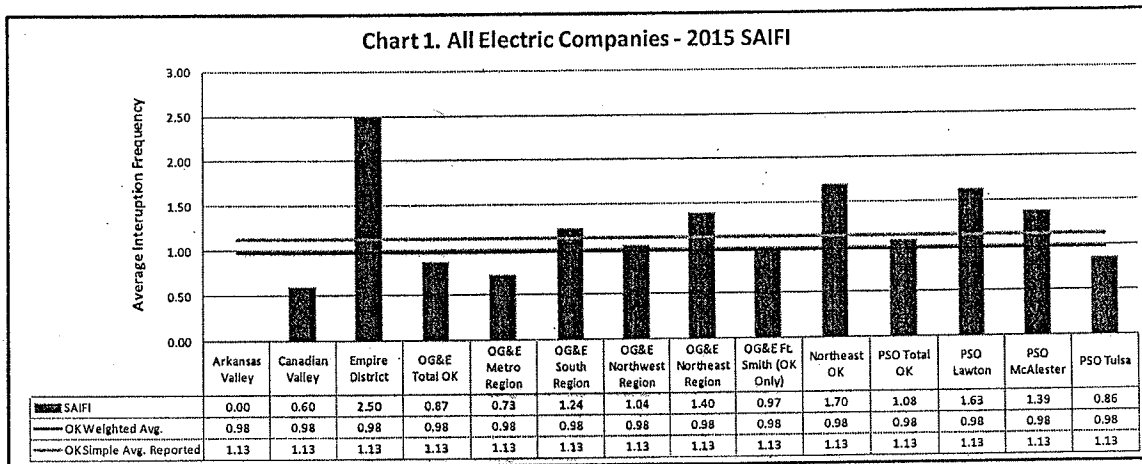
5.0 Analysis

5.1 SAIFI Trends and Patterns

⁵ Definitions are given to help readers better understand the information that goes into the calculations that are used in this document. The basis of many of these definitions is included in IEEE Standard 100-1996; however, PUD has presented the definitions in a more user-friendly format for explanation purposes.

⁶ The distribution system is considered anything from the distribution substation fence to the customer meter. Often the initial over current protection and voltage regulator are within the substation fence.

The following graph shows the Oklahoma outage or SAIFI data for the year 2015 by utility and region⁷:



The chart suggests that Empire’s Oklahoma customers experienced an average of 2.50 power outages or interruptions in 2015. Canadian Valley’s customers were without power, on average, 0.60 times, and NOEC customers were without power, on average, 1.70 times last year. The customers of OG&E and PSO, the state’s largest electric companies, were without power in 2015 an average of 0.87 and 1.08 times, respectively. Overall during 2015, Oklahoma electric customers served by a regulated utility were without power, on average, approximately 1.13 times.⁸

Historically, Empire’s Oklahoma customers, experiencing an average of 1.989 outages per year, lost power more often than customers of any other regulated electric utility in Oklahoma during the past five years. The customers of Canadian Valley lost power the least often, experiencing an average of only about 0.618 outages per year over the past five years.

Oklahoma customers served by a regulated electric utility experienced 1.233 outages per year on average over the past five years. Average historical outage data for Oklahoma’s regulated power utilities is shown in the following chart:

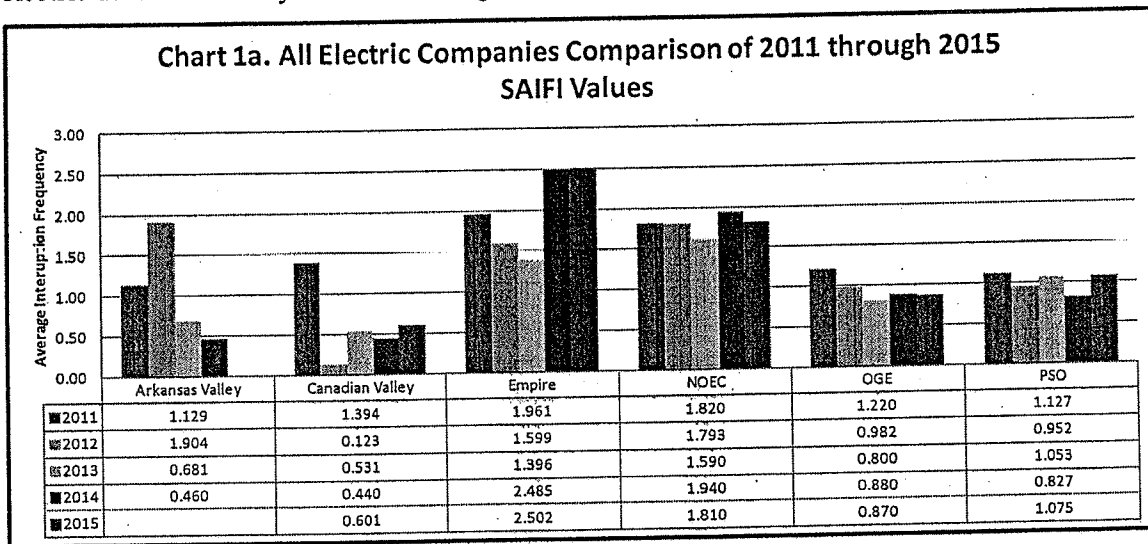
⁷ The SAIFI and SAIDI reliability indices are based on 12 months of system performance data ending December 31, 2015, and exclude “Major Events” as defined by OAC 165:35-25-13. The Oklahoma Average SAIFI and SAIDI were estimated by first computing a weighted average of the combined data for each statistic and then computing a simple (unweighted) average in a similar manner.

⁸ The simple SAIFI average for all of Oklahoma’s regulated utilities is slightly below 1.13 and the metric’s weighted average is roughly 0.98.

SAIFI VALUES						
Company	2011	2012	2013	2014	2015	Mean
Arkansas Valley	1.129	1.904	0.681	0.460		1.043
Canadian Valley	1.394	0.123	0.531	0.440	0.601	0.618
Empire	1.961	1.599	1.396	2.485	2.502	1.989
NOEC	1.820	1.793	1.590	1.940	1.810	1.791
OGE	1.220	0.982	0.800	0.880	0.870	0.950
PSO	1.127	0.952	1.053	0.827	1.075	1.007
Average	1.442	1.225	1.008	1.172	1.372	1.233

Electrical outages can be caused by severe weather, engineering problems, or other company-specific causes, as well as by external actions, such as a vehicle striking a power pole and causing it and potentially other poles to fall and disconnect power lines. The OCC monitors customer outage data required to be reported by all Commission-regulated Oklahoma electric utilities and investigates any unusual occurrences.

The bar charts and table below show SAIFI outage data for each of Oklahoma’s regulated electric utilities for the years 2011 through 2015⁹:

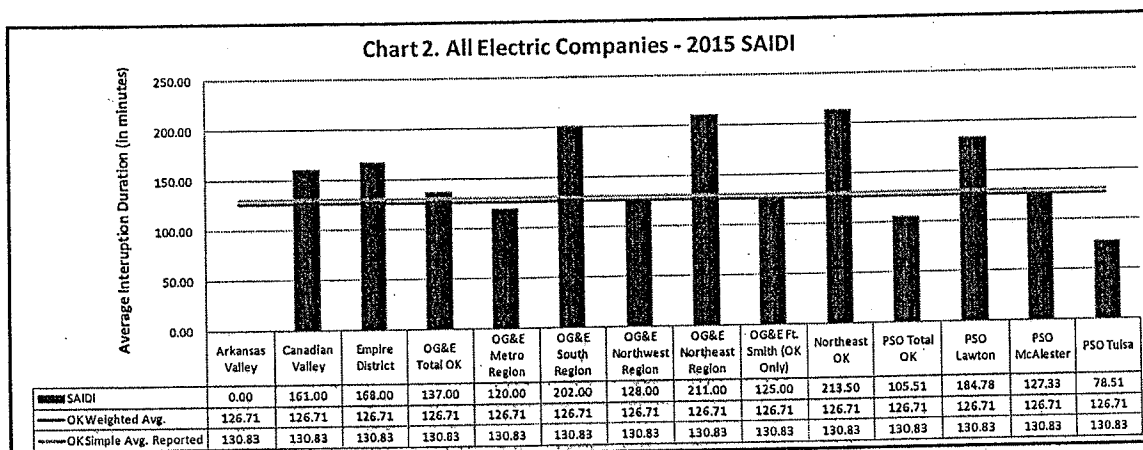


5.2 SAIDI Trends and Patterns

The following bar chart and table show SAIDI data from Oklahoma regulated electric utilities regarding the average duration in minutes of power outages during 2015 by utility and region of the State¹⁰:

⁹ Data points for each regulated Oklahoma electric utility that provided SAIFI indices for year 2015 and the four prior years were plotted to present a visual comparison among the utilities. SAIFI averages were calculated using data provided by each of the six Commission-regulated utilities.

¹⁰ The weighted SAIDI mean for 2015 was approximately 126.71 minutes, while the simple SAIDI average was 130.83 consumer minutes. Therefore, customers consuming power from Oklahoma’s regulated electric utilities in 2015 were probably without electricity for 2.112 hours to 2.181 hours during the year.



Of Oklahoma’s six electricity providers regulated by the Commission that are included in this report, NOEC customers averaged the most time without power in 2015, that being 213.50 minutes, or 3.558 hours. That is 0.134 hours more outage time than the average of 205.44 minutes experienced by NOEC customers in 2014. PSO customers were without power for the shortest time in 2015, an average of 105.51 minutes. OG&E and Canadian Valley customers were without power an average of 137.00 and 161.00 minutes, respectively, during 2015. Altogether, customers of Oklahoma’s regulated electric utilities were without power for an average of 130.83 minutes last year.

Over the past five years, NOEC and Arkansas Valley customers, on average, were without power the longest, while PSO customers averaged the least amount of power outage time during the period.

The table below shows the average time in minutes that a customer of the six subject utilities was without power in each of the past five years:

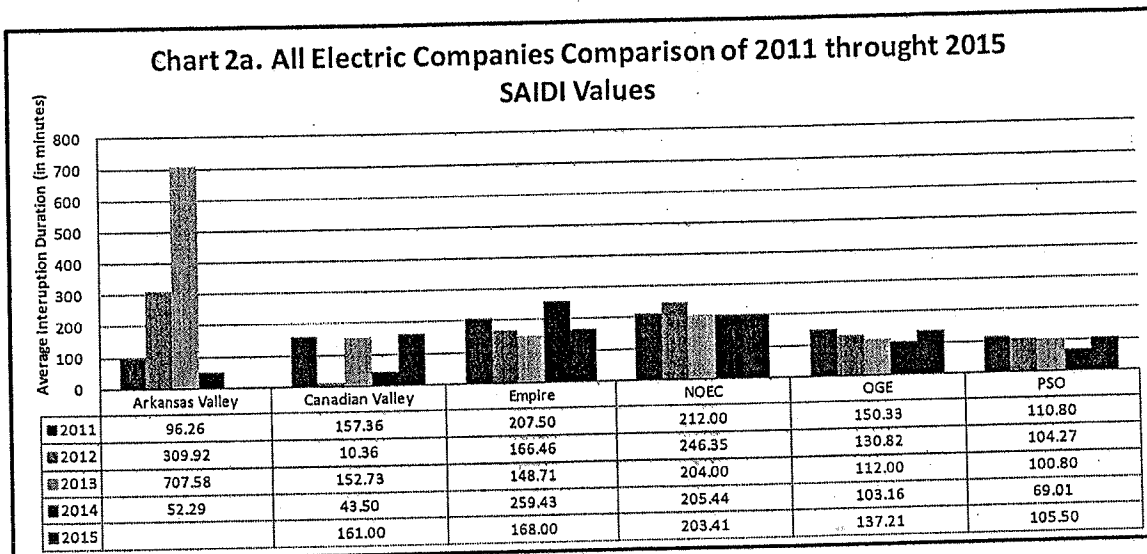
SAIDI VALUES*						
Company	2011	2012	2013	2014	2015	Mean
Arkansas Valley	96.26	309.92	707.58	52.29		291.51
Canadian Valley	157.36	10.36	152.73	43.50	161.00	104.99
Empire	207.50	166.46	148.71	259.43	168.00	190.02
NOEC	212.00	246.35	204.00	205.44	203.41	214.24
OG&E	150.33	130.82	112.00	103.16	137.21	126.70
PSO	110.80	104.27	100.80	69.01	105.50	98.08
Average	155.71	161.36	237.64	122.14	155.02	170.92

*SAIDI Values are presented in minutes

On average, a customer served by a regulated electric utility was without power for 170.92 minutes or 2.849 hours per year over the five-year period. Customers being served by the state’s largest electric utilities, OG&E and PSO were without power on average for 126.70 minutes or 2.112 hours per year, and for 98.08 minutes or 1.635 hours per year, respectively, over the five-year period. Overall, the average amount of time that a customer of Oklahoma’s regulated

electric utility sector was without power during 2015 was the second shortest of any year during the past five years. The OCC is actively monitoring electrical outages and inquiring into causes and believes the average outage time in 2016 will be even lower.

Chart 2a below displays the 2011-2015 SAIDI outage results for Oklahoma's six regulated electric utilities in a more visual form:



An inspection of the graph reveals that PSO, NOEC, and OGE over the past five years experienced relatively slight changes in the duration of outages, suggesting that service during that period was more consistently reliable than the service of the other three regulated electric utilities in the state. Differences in the length of outages were principally due to irregular or locally variable weather, although company-specific factors, such as the availability of linemen to more quickly restore power, also affected the duration of power losses.

The results cited above show that some of Oklahoma's regulated electric utilities have succeeded in improving their service reliability and reducing the number and duration of power outages. Others of these electric utilities have more work to do to achieve gains in service reliability achieved by the most reliable service providers. But all of Oklahoma's retail electric utilities must continue their efforts to minimize the frequency and duration of power outages. In all cases, the OCC is committed to working with each regulated utility to try to facilitate improvements in delivery of safe and reliable electricity in a way that minimizes costs to ratepayers while ensuring quality service.

6.0 Commission Rules Summary

OAC 165:35-25-14. Reliability program

Each utility, to the maximum extent practicable, shall design and maintain a program to minimize the frequency and duration of electric service interruptions in Oklahoma. The program should include inspection, maintenance, repair, and replacement standards that ensure the most

timely service restoration as well as preventive and emergency maintenance as needed to minimize outages, and should prioritize efforts to give special emphasis first to the improvement of the worst performing circuits in each region. The program should include, at a minimum, efforts to address:

- 1) The age, distribution, and location of equipment on each circuit.
- 2) The number, density, and location of customers on each circuit.
- 3) The location and density of trees on the system.
- 4) An annual vegetation management plan.
- 5) The impacts of animals, wind, storms, ice and auto accidents on electric distribution system reliability.

OAC 165:35-25-20. Annual reliability report

Each electric utility shall submit an annual reliability report to the Commission by March 1 of each year. The Commission may request additional data, but the report shall include the following:

- 1) A description of all vegetation management performed by the utility in the previous calendar year and plans for the current year.
- 2) SAIDI and SAIFI values computed for the utility's entire service territory and displayed in tabular form.
- 3) SAIDI and SAIFI values computed for each of the utility's regions and displayed in tabular form.
- 4) A detailed report for each major event not included in calculation of the reliability indices. The major event report shall include the interruption cause or causes, date, regional location, percentages of customers without service in that region as a result of the event, the time at which service was lost to 10 percent or more of customers in that region, the time when the last customer's service was restored in that region, and any other details that the utility or the Commission believes will further justify the exclusion of the event from the calculation of reliability indices.
- 5) A description of the program the utility is using to analyze and improve its worst performing circuits and a summary of the results of that program for the reporting year.
- 6) A description and map identifying the utility's service regions or operating divisions, as well as documentation and illustration of any changes during the reporting year in region boundaries, as defined by the utility, and justification for such changes.
- 7) For each utility with less than 100,000 customers, the utility must show the data used to calculate service reliability as well as the rural adjusted minimum performance level.

7.0 System Average Interruption Indices

SAIFI: *System Average Interruption Frequency Index* (sustained interruptions). This measures the average number of sustained interruptions (five minutes or more of zero voltage per incident)

per consumer during a year. It is the ratio of the annual number of interruptions to the number of consumers (Total number of sustained interruptions in a year / Total number of consumers).

SAIDI: *System Average Interruption Duration Index.* This is a measure of the average duration of interruptions per consumers during the year. It is the ratio of the annual duration of interruptions (sustained) to the number of consumers (Total duration of sustained interruptions in a year / Total number of consumers). In other words, when power is lost, SAIDI is the average length of time customers were without power.

CAIDI: *Customer Average Interruption Duration Index.* This represents the average time required to restore service. CAIDI is calculated by dividing SAIDI by SAIFI.

8.0 Sample Calculations

$$\text{SAIFI} = \frac{200 + 600 + 25 + 90 + 700 + 1,500 + 100}{2,000} = 1.6075$$

$$\text{SAIDI} = \frac{(8.17 * 200) + (71.3 * 600) + (30.3 * 25) + (267.2 * 90) + (120 * 700) + (10 * 1,500) + (40 * 100)}{2,000} = 86.11 \text{ min}$$

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{86.110}{1.6075} = 53.567 \text{ min}$$

The value of these standards in assessing an electric utility's performance can help point to specific areas where more attention by the utility is necessary to improve reliability. From analysis of these calculations and correlation with actual events, causes of outages can be identified on a systemic basis and reliability improvement plans can be developed. For example, the extent that an electric utility routinely inspects utility poles to determine those most susceptible to deterioration and collapse, conclusions can be drawn and plans to mitigate such deterioration and collapse can be developed to achieve more favorable results from reliability indices. A common finding, for instance, is that a lack of "vegetation management", or tree trimming, is responsible for outages along specific circuits. There may be a number of reasons why plant life has grown too close to power lines, but the fix is often relatively simple.

Other reasons for interruptions may be more difficult to detect, such as animals on poles or along wires, resulting in shorts and the subsequent interruptions. Whatever the reason for an interruption or series of interruptions, these reliability calculations can assist the utility to determine primary causes of outages and develop a plan to try to avoid as many future outages as possible and to restore reliable flow of electricity to customers as quickly as possible.