

REDACTED

FILED
DEC 16 2014

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF)
OKLAHOMA GAS AND ELECTRIC COMPANY)
FOR COMMISSION AUTHORIZATION OF A)
PLAN TO COMPLY WITH THE FEDERAL CLEAN)
AIR ACT AND COST RECOVERY; AND FOR)
APPROVAL OF THE MUSTANG MODERNIZATION)
AND COST RECOVERY)

CAUSE NO. PUD 201400229

RESPONSIVE TESTIMONY

OF

CRAIG R. ROACH, Ph.D.

ON BEHALF OF

OKLAHOMA CORPORATION COMMISSION

PUBLIC UTILITY DIVISION

DECEMBER 16, 2014

TABLE OF CONTENTS

I. QUALIFICATIONS..... 1

II. PURPOSE AND SUMMARY 4

III. OG&E'S EVALUATION OF ALTERNATIVES FOR ITS ENVIRONMENTAL COMPLIANCE PLAN HAS MERIT, BUT DEFICIENCIES REMAIN 15

 A. THE POLICY STANDARD FOR THIS PROCEEDING REQUIRES OG&E TO DEMONSTRATE THE REASONABLENESS OF THE COSTS TO BE RECOVERED 15

 B. OG&E WITNESSES IDENTIFY THE POWER PLANT UNITS AFFECTED AND DESCRIBE THE ENVIRONMENTAL CONTROLS REQUIRED ON EACH OF THEM 20

 C. OG&E PRESENTS THE METHODS AND RESULTS OF ITS EVALUTION OF ALTERNATIVE COMPLIANCE OPTIONS 27

 D. DEFICIENCIES MEAN OG&E'S EVALUATION PROCESS IS NOT SUFFICIENT TO SUPPORT ITS COMPLIANCE PLAN AS-IS 30

IV. OG&E'S EVALUATION OF ALTERNATIVES FOR ITS MUSTANG MODERNIZATION PLAN ALSO IS DEFICIENT 44

V. OG&E'S RATE RECOVERY PROPOSAL PUTS TOO MUCH RISK ON THE SHOULDERS OF RATEPAYERS 49

VI. CONCLUSIONS AND RECOMMENDATIONS..... 64

 A. ENVIRONMENTAL COMPLIANCE PLAN 64

 B. MUSTANG MODERNIZATION PLAN..... 66

ATTACHMENT ONE: THE COMMISSION'S EXPERIENCE WITH PSO'S PROPOSED ENVIRONMENTAL COMPLIANCE PLAN GIVES IT A USEFUL POINT OF COMPARISON AND HIGHLIGHTS MAJOR ISSUES TO ADDRESS 69

REDACTED

1 I. **QUALIFICATIONS**

2 **Q. Please state your name, position, and business address.**

3 A. My name is Craig R. Roach. I am the President as well as the Founder of
4 Boston Pacific Company, Inc. ("Boston Pacific"). My business address is 1100
5 New York Avenue, NW, Suite 490 East, Washington, DC 20005.

6

7 **Q. What is your relationship to the Oklahoma Corporation Commission Staff**
8 **("Staff"), Public Utility Division?**

9 A. Boston Pacific has been hired to provide consulting and independent expert
10 witness services to assist and represent Staff in this proceeding. The views
11 expressed herein are my own.

12

13 **Q. Please summarize your educational background.**

14 A. I earned my Ph.D. in Economics from the University of Wisconsin and my
15 Bachelor of Science Degree in Economics, cum laude, from John Carroll
16 University. I served on the Advisory Board to the University of Wisconsin's
17 Department of Economics from 2007 to 2014.

18

19 **Q. Please summarize your professional background.**

20 A. I have 39 years of experience working on investments in, policies for, and
21 litigation concerning the electricity, natural gas and other energy businesses.
22 Boston Pacific is a consulting and investment services firm specializing in the
23 electricity and natural gas businesses. For 27 years, Boston Pacific has served

REDACTED

1 the full range of stakeholders: public utility commissions, regional transmission
2 organizations, competitive power suppliers, electric utilities, electric and gas
3 marketers, gas pipeline companies, electric transmission companies, trade
4 associations, government agencies, and energy consumers. Prior to Boston
5 Pacific, I was an economist with the U.S. Congressional Budget Office and a
6 Project Manager with ICF Incorporated, an energy and environmental consulting
7 firm.

8
9 **Q. Do you have experience as an expert witness?**

10 A. Yes. I have extensive experience as an expert witness, having submitted
11 testimony, affidavits, or comments to the U.S. Federal Energy Regulatory
12 Commission ("FERC") in more than 30 proceedings, to public utility commissions
13 in 25 states plus the District of Columbia (some on multiple occasions), to three
14 Canadian regulatory bodies, in arbitrations, and in state and federal courts of law.
15 A list of my submissions is contained in Exhibit No. CRR-1. Also shown therein
16 is a list of my professional speeches and articles.

17
18 **Q. Have you previously testified before the Oklahoma Commission?**

19 A. Yes. Most recently, I submitted in 2013 Responsive, Rebuttal, and Surrebuttal
20 Testimony on behalf of the Staff and the Office of the Attorney General of
21 Oklahoma in Cause No. PUD 201200054.¹ These three testimonies assessed a

¹ Responsive Testimony of Craig R. Roach on Behalf of The Oklahoma Corporation Commission Staff and The Office of the Attorney General of Oklahoma, Oklahoma Corporation Commission Cause No. PUD 201200054, filed January 8, 2013 ("Roach Responsive Testimony in Cause No. PUD 201200054"); Rebuttal Testimony of Craig R. Roach on Behalf of The Oklahoma Corporation Commission Staff and The

REDACTED

1 cost recovery request for a proposed environmental compliance plan submitted
2 by Public Service Company of Oklahoma ("PSO"). I addressed many of the
3 same issues that arise in this proceeding.

4
5 I also submitted Responsive Testimony on September 10, 2012 concerning
6 PSO's request for contract earnings, and testified at trial in November 2012.²

7
8 In 2010, I submitted testimony related to Oklahoma Gas & Electric's Application
9 to construct the Crossroads wind farm.³

10
11 **Q. Has Boston Pacific served as an Independent Evaluator for the Oklahoma
12 Commission?**

13 A. Yes, Boston Pacific served as the Commission's Independent Evaluator in the
14 2012 competitive procurement in which Calpine was awarded a power purchase
15 agreement (Cause No. PUD 201200054). We previously served the Oklahoma
16 Commission as its Independent Evaluator for the design and implementation of
17 the competitive procurement in 2008 in which Exelon Generation, LLC was
18 awarded a power purchase agreement (Cause No. PUD 200700418).

Office of the Attorney General of Oklahoma, Oklahoma Corporation Commission Cause No. PUD 201200054, filed February 11, 2013 ("Roach Rebuttal Testimony in Cause No. PUD 201200054"); Surrebuttal Testimony of Craig R. Roach on Behalf of The Oklahoma Corporation Commission Staff and The Office of the Attorney General of Oklahoma, Oklahoma Corporation Commission Cause No. PUD 201200054, filed March 22, 2013 ("Roach Surrebuttal Testimony in Cause No. PUD 201200054").

² Responsive Testimony of Craig R. Roach on Behalf of The Oklahoma Corporation Commission Staff and The Office of the Attorney General of Oklahoma, Oklahoma Corporation Commission Cause No. PUD 201200079, filed September 10, 2012 ("Roach Responsive Testimony in Cause No. PUD 201200079").

³ Direct Testimony of Craig R. Roach on Behalf of The Oklahoma Corporation Commission, Oklahoma Corporation Commission Cause No. PUD 201000037, filed June 11, 2010 ("Roach Direct Testimony in Cause No. PUD 201000037").

REDACTED

1

2 **Q. Please provide some examples of Boston Pacific's recent work and**
3 **expertise beyond that in Oklahoma.**

4 A. Boston Pacific does substantial work as an independent monitor for electricity
5 markets and competitive solicitations. Since 2004, Boston Pacific has served as
6 an independent advisor to the Southwest Power Pool ("SPP") Board of Directors;
7 much of this work has involved market design and market rules for the wholesale
8 electricity markets. Boston Pacific has also served since 2004 as an
9 independent monitor for many competitive solicitations including those in the
10 District of Columbia, Delaware, Hawaii, Illinois, Maryland, Mississippi, New
11 Jersey, Ohio, Oregon, Pennsylvania, and elsewhere; in this work, Boston Pacific
12 generally reports to the state regulatory commission.

13

14 Boston Pacific also has conducted substantial financial and market consulting for
15 power investments throughout North America and in about two dozen countries
16 around the world. We also serve as advisors on major new technology policies
17 and procurements; examples include our work on offshore wind in New Jersey
18 and work on major clean coal projects in both Mississippi and Illinois.

19

20 **II. PURPOSE AND SUMMARY**

21 **Q. What is the purpose of your Responsive Testimony?**

22 A. The purpose of my Responsive Testimony is to report on my review of Oklahoma
23 Gas and Electric's ("OG&E's") application for (a) authorization of and cost recovery

REDACTED

1 for its plan to comply with the Federal Clean Air Act – OG&E’s “environmental
2 compliance plan” and (b) authorization of and cost recovery for its plan for
3 modernization at its Mustang power facility – OG&E’s “Mustang modernization
4 plan.”⁴

5

6 **Q. What is the backdrop for OG&E’s environmental compliance plan?**

7 A. The backdrop is that, as with other utilities across the country, OG&E had to
8 propose efforts to comply with two major environmental rules under the federal
9 Clean Air Act: The Regional Haze Rule (“RHR”) and the Mercury and Air Toxics
10 Standards (“MATS”). Suffice it to say that there was a difference of opinion
11 between OG&E and the federal government on what had to be done to comply
12 with the sulfur dioxide emissions provision of the RHR. Specifically, Oklahoma’s
13 State Implementation Plan in this respect was rejected by the U.S. Environmental
14 Protection Agency (“U.S. EPA”) in favor of its stricter Federal Implementation
15 Plan.⁵ OG&E appealed this decision all the way to the U.S. Supreme Court, which
16 declined to hear the appeal.⁶

17

18 **Q. What actions are at the core of this proceeding?**

19 A. The actions most likely to be at the core of this proceeding are those directed at
20 complying with the sulfur dioxide emissions standard under the RHR. That is not

⁴ OG&E Application, Oklahoma Corporation Commission Cause No. PUD 201400229, filed August 6, 2014 (“OG&E Application”).

⁵ 76 Fed. Reg. 16,168, available at <http://www.gpo.gov/fdsys/pkg/FR-2011-03-22/pdf/2011-5799.pdf>.

⁶ 13-921 OKLAHOMA, ET AL. V. EPA, ET AL., http://www.supremecourt.gov/orders/courtorders/052714zor_5fci.pdf

REDACTED

1 to say there are no other significant actions proposed as part of OG&E's
2 environmental compliance plan for the RHR and MATS in full – there are.

3

4 **Q. What actions does OG&E propose to address the federal regulations for**
5 **sulfur dioxide?**

6 A. OG&E proposes (a) to retrofit two large (520 MW and 522 MW) coal-fired power
7 plant units at its Sooner facility with control equipment called dry Flue Gas
8 Desulfurization (“dry FGD” or generally “scrubbers”) and (b) to convert two large
9 (492 MW and 506 MW) coal-fired units at its Muskogee facility to burn natural gas
10 instead of the coal they now burn. OG&E refers to this combination of actions as
11 its *Scrub/Convert* alternative.

12

13 **Q. Did OG&E evaluate other alternatives?**

14 A. Yes. OG&E proposed and evaluated four alternatives alongside *Scrub/Convert*.
15 The other four are (a) the *Scrub* alternative in which scrubbers are retrofitted on all
16 four of these coal-fired units at Sooner and Muskogee; (b) the *Convert* alternative
17 in which all of these four coal-fired units are converted to burn natural gas; (c) the
18 *Scrub/Replace* alternative in which the two Sooner units are retrofitted with
19 scrubbers and the two Muskogee units are replaced with newly-built natural gas-
20 fired combined cycle power plants; and (d) the *Replace* alternative in which all four
21 units are replaced with newly-built natural gas-fired combined cycle power plants.⁷

⁷ Direct Testimony of Leon Howell on Behalf of Oklahoma Gas and Electric Company, Oklahoma Corporation Commission Cause No. PUD 201400229, filed August 6, 2014 (“Howell Direct Testimony”), page 5, Figure 1.

REDACTED

1

2 **Q. How were these five alternatives evaluated?**

3 A. The five alternatives that OG&E proposed were evaluated by forecasting and
4 comparing the present value of OG&E's system-wide costs over a 30-year period.
5 Moreover, these cost comparisons were done under nine different sensitivities or
6 scenarios about the future. These nine scenarios varied in their forecasts of the
7 pace at which other utilities in the Southwest Power Pool ("SPP") converted to
8 natural gas, the level of natural gas prices, the existence of a tax on carbon dioxide
9 emissions, the levels of SPP load, and capital costs for the environmental
10 controls.⁸

11

12 **Q. What were the results of these cost comparisons?**

13 A. The results were that OG&E's cost estimates for the five alternatives it proposed
14 were often very close, especially for the first three alternatives. Notably, despite
15 the fact that OG&E proposed the *Scrub/Convert* alternative as the best, that
16 alternative is never the sole alternative ranked lowest cost; the best *Scrub/Convert*
17 does in the rankings is that it is tied as the lowest cost alternative in three of the
18 nine scenarios.⁹ The *Scrub* alternative wins in three scenarios and the *Convert*
19 alternative wins the remaining three scenarios.¹⁰ However, the margin of victory
20 is often just \$0.1 billion, which is quite small in this context.

⁸ Oklahoma Gas and Electric Company 2014 Integrated Resource Plan (OG&E 2014 IRP), Table 19, page 44 and Table 20, page 46.

⁹ The costs being compared here have all been rounded to the nearest \$0.1 billion, which is how the data is presented in the OG&E 2014 IRP.

¹⁰ See Table One, page 29.

REDACTED

1

2 **Q. Was the absence of one clear winner in the cost comparison surprising to**
3 **you?**

4 A. No. This simply reflects the uncertainty about the future. For example, in the high
5 natural gas price scenario, as expected, the *Scrub* alternative was the lowest cost
6 at \$24.7 billion, and the cost of the *Scrub/Convert* alternative was 4.5 percent
7 higher than that. This was expected because retrofitting and keeping the old coal
8 units would look less expensive than the *Convert* alternative, which depends more
9 heavily, directly or indirectly, on natural gas. However, in the low gas price
10 scenario, the *Convert* alternative was the lowest cost, and *Scrub/Convert* was 3.0
11 percent higher. This was expected because converting to natural gas would look
12 less expensive with low natural gas prices.

13

14 **Q. What should be done in the face of uncertainty or risk like this?**

15 A. The standard recommendation to address uncertainty is to diversify your actions.
16 For example, in the face of uncertainty about stock prices, the common tactic is to
17 buy a diversified portfolio of stocks. However, to identify the best portfolio of
18 actions, a complete assessment of alternative actions and uncertainties must be
19 conducted.

20

21 **Q. Is OG&E's evaluation of the alternatives and uncertainties complete?**

22 A. No. Having reviewed OG&E's evaluation of the five compliance alternatives that
23 it proposed, I conclude that OG&E's evaluation is incomplete.

REDACTED

1

2 **Q. Why is OG&E's evaluation incomplete?**

3 A. OG&E's evaluation is incomplete because of five remaining deficiencies;
4 surprisingly, they remained even after we made OG&E aware of them in both data
5 requests and a phone call on November 19, 2014, and after we asked them to fill
6 those deficiencies with specific analyses for the record.

7

8 **Q. In summary form, what are the five remaining deficiencies?**

9 A. The first deficiency is that OG&E has not assessed existing, natural gas-fired
10 power plant capacity as an alternative. OG&E did not conduct a competitive
11 solicitation or a thorough survey of any sort to test the availability of existing natural
12 gas-fired combined cycle plants. An existing combined cycle unit might have
13 reduced the cost of the *Scrub/Replace* and *Replace* alternatives.

14

15 Even Boston Pacific's own, limited survey readily found two substantial entities (J
16 Power and LS Power) that had existing or new natural gas-fired combined cycle
17 power to offer to OG&E. Notably, OG&E made no mention of these opportunities.

18

19 The second deficiency is that OG&E did not assess the possibility that new
20 environmental regulations could shut the retrofitted Sooner units before the end of
21 its 30-year analysis timeframe, in 2044. Cutting their operating life short would
22 make the *Scrub/Convert* and *Scrub* alternatives more expensive. The probability
23 is high for tightened federal regulation on coal-fired power plants given what is

REDACTED

1 often characterized as the U.S. EPA's "Campaign on Coal." OG&E discusses this
2 possibility at length in its testimony, but does not assess the implications for its
3 investment in scrubbers.

4
5 The third deficiency is that OG&E did not fully assess the effect of higher or lower
6 load (both capacity and energy) on its own system. Changes in the need for
7 capacity and energy could affect the choice of compliance option.

8
9 The fourth deficiency is that OG&E's sensitivity analyses are overly simplistic
10 because they change just one variable at a time. Scenarios weighing multiple
11 changes should have been run to be more realistic. For example, a carbon tax
12 would increase the demand for natural gas, which, in turn, could increase the price
13 of natural gas. Thus a scenario that combines such a tax with high natural gas
14 prices is a realistic scenario.

15
16 The fifth deficiency is that OG&E relies on forecasts of SPP Market prices which
17 are inconsistent with other assertions OG&E makes. For example, OG&E asserts
18 that new combined cycle plants will be built as early as 2018, but the SPP market
19 prices OG&E forecasts are not high enough to justify that investment. These
20 natural gas prices are key to support its choice to convert units at Muskogee rather
21 than to replace them with existing or new combined cycle units; the *Convert*
22 alternatives rely more heavily on purchases from the SPP Market than would a
23 *Replace* alternative.

REDACTED

1 **Q. Given these deficiencies, what do you recommend to the Commission?**

2 A. I recommend that the Commission approve OG&E's choice of its *Scrub/Convert*
3 environmental compliance alternative, but to do so *with conditions*. I recommend
4 approval because this alternative appropriately offers a diversified portfolio of
5 actions in the face of uncertainties. However, the precise mix of actions that OG&E
6 chose relies heavily on the alternatives that OG&E analyzed and on the
7 assumptions that OG&E used in its analyses. OG&E's analysis is incomplete so
8 conditions are necessary to put the risk of that incompleteness on OG&E rather
9 than on the Oklahoma ratepayer.

10

11 **Q. What conditions do you recommend?**

12 A. For the two retrofitted coal units at the Sooner facility, I recommend that approval
13 be subject to the condition that, if these units are shut down at any time prior to
14 2044, OG&E would not receive compensation for stranded investment. Related to
15 this is the condition that the recovery of capital costs be over the assumed book
16 life used in OG&E's analysis.¹¹ In addition, I recommend that OG&E be held to
17 the capital cost and operating performance that it assumed for the retrofitted
18 Sooner plants.

19

¹¹ For OG&E's assumed book lives and tax lives of the various plant and equipment, see Exhibit CRR-2, which includes OG&E's response to Data Request OIEC 3-12, Attachment 71.

REDACTED

1 For the two units at Muskogee, I recommend that OG&E be held to the capital cost
2 and operating performance that it assumed for these converted plants. Operating
3 performance here includes, for its converted plants, heat rate, ramp rate, and cold
4 and hot start times. Further, these operating parameters would limit cost recovery
5 for the participation of the Muskogee units in the SPP market. For example, the
6 assumed heat rate curve for the converted Muskogee units would limit fuel cost
7 recovery.

8

9 **Q. Let's turn to OG&E's Mustang modernization plan. Please briefly summarize**
10 **that plan.**

11 A. The essence of the Mustang modernization plan is that OG&E would retire the
12 existing Mustang units earlier than was expected in its 2012 Integrated Resource
13 Plan ("IRP"), and then replace that capacity with new natural gas-fired combustion
14 turbines that OG&E would build at that same site.

15

16 **Q. What is your conclusion about OG&E's Mustang modernization plan?**

17 A. Having reviewed the Mustang modernization plan, I find that OG&E's assessment
18 of it is incomplete.

19

20 **Q. How is OG&E's assessment incomplete?**

21 A. OG&E's assessment of the Mustang modernization plan is incomplete because
22 OG&E failed to assess the full range of reasonable alternatives to the replacement
23 of the aging Mustang capacity. That is, OG&E only fully considered new

REDACTED

1 combustion turbines that OG&E itself would build at the Mustang site. OG&E did
2 not fully evaluate existing and new combined cycle units at the Mustang site or at
3 any other location, whether the units are built by OG&E or by independent power
4 producers.

5

6 **Q. Did OG&E try to support its narrowed assessment?**

7 A. Yes. OG&E argued that the Mustang site is uniquely important for system
8 reliability. In a later data response, however, OG&E backed off by agreeing that
9 any power plant which qualifies as a Network Resource in SPP would be
10 comparably important to system reliability.¹² OG&E also tried to justify its
11 accelerated plan for the Mustang retirements by saying that the old units would
12 suffer greater break downs if they were subject to the stop-and-start dispatch likely
13 in the SPP Market. However, OG&E's own analysis shows the opposite. For
14 example, in the 2012 IRP the Mustang units were forecasted to start 77 times in
15 2017, while in the new, 2014 IRP they are started just 12 times. Additionally, while
16 the 2012 IRP forecast 132 starts for the Mustang units in 2014, starts are no higher
17 – just 104 so far in 2014.¹³

18

19 **Q. Did OG&E speed up any of the Mustang retirements in its plan?**

¹² Exhibit CRR-3, OG&E response to Data Request PUDKC 3-8(b).

¹³ Exhibit CRR-4, OG&E response to Data Request PUDKC 3-9, OCC 3-9_Att1 and OCC 3-9_Att2.

REDACTED

1 A. Yes. As compared to the 2012 IRP, OG&E sped up the retirement of (a) Unit 3
2 (121 MW) by 3 years, from the end of 2020 to the end of 2017, and (b) Unit 4 (242
3 MW) by 7 years, from the end of 2024 to the end of 2017.

4
5 **Q. What do you recommend to the Commission?**

6 A. I recommend that the Mustang modernization plan be deferred until the successful
7 completion of a competitive procurement. Bids would be invited from both natural
8 gas-fired combustion turbines and combined cycle plants. As was done in
9 previous procurements, SPP would be asked to judge whether such a designation
10 would necessitate system costs, which would be included in bid evaluation.

11
12 In addition, any bidder should be eligible to build at the Mustang site so that
13 Oklahoma ratepayers can enjoy the potential for lower costs that might result.
14 Finally, OG&E would be required to bid under the same rules as all other bidders.
15 As to the timing of Mustang's retirement, the bids would determine the best pace.

16
17 **Q. Do you have any recommendations related to OG&E's rate proposal?**

18 A. Yes. I recommend that the discussion of rate recovery be deferred until OG&E's
19 rate case. However, I recommend that the Commission rule here that the
20 proposed conditions for approval of both the environmental compliance plan and
21 the Mustang modernization plan be incorporated into the ultimate rate case
22 decision including any fuel adjustment clause implementation.

23

REDACTED

1 **Q. Has the Commission encountered any of the issues raised here in another**
2 **proceeding?**

3 A. Yes. The Commission encountered many of the same issues in the proceeding
4 on PSO's environmental compliance plan in Cause No. PUD 201200054. Because
5 the PSO proceeding could be useful in identifying both issues and remedies here,
6 Attachment One provides an extensive summary of the PSO proceeding.

7
8 **III. OG&E'S EVALUATION OF ALTERNATIVES FOR ITS ENVIRONMENTAL**
9 **COMPLIANCE PLAN HAS MERIT, BUT DEFICIENCIES REMAIN**

10 **A. THE POLICY STANDARD FOR THIS PROCEEDING REQUIRES OG&E TO**
11 **DEMONSTRATE THE REASONABLENESS OF THE COSTS TO BE**
12 **RECOVERED**

13 **Q. What is the policy standard OG&E suggests for this proceeding?**

14 A. OG&E's view on the policy standard that the Commission must apply in assessing
15 this application starts with its Application, in which OG&E states: "The Commission
16 has jurisdiction in these proceedings by virtue of Article IX, Sections 18 and
17 following of the Constitution of the State of Oklahoma, the Oklahoma statutes,
18 including 17 O.S. § 286, 17 O.S. § 151, *et seq.*, and 17 O.S. § 251 *et seq.*, and the
19 Commission's rules."¹⁴

20
21 **Q. What part of the statutes apply to OG&E's environmental compliance plan?**

¹⁴ OG&E Application, page 3.

REDACTED

1 A. The part that applies to OG&E's environmental compliance plan is 17 O.S. §
2 286(B).

3

4 **Q. What portion of this part of the statute would you like to point out?**

5 A. I point to the section that applies to a utility seeking approval of capital expenditures
6 under the Clean Air Act. Specifically, the statute states: "the reasonableness of
7 the costs to be recovered by the utility shall be subject to Commission review and
8 approval."¹⁵

9

10 In addition, I point to the Commission rules that implement the statute and which
11 also require Commission review and approval of the "reasonableness of the
12 costs."¹⁶

13

14 **Q. How should the Commission judge the reasonableness of costs?**

15 A. To judge the reasonableness of costs, the Commission should require OG&E to
16 present a review of alternative approaches. OG&E recognized this when it
17 specified five compliance alternatives and evaluated them under nine different
18 views or sensitivities about the future. In my view, those alternatives should
19 include competitive alternatives.

20

21 **Q. What part of the statutes apply to OG&E's Mustang modernization plan?**

¹⁵ 17 O.S. §286 (B).

¹⁶ Commission Rules, 165:35-38-4(d).

REDACTED

1 A. I point to 17. O.S. § 286(C)(1), which explains what OG&E must do to recover
2 the costs of the expenditures in its Application. It states:

3 An electric utility subject to rate regulation by the Corporation
4 Commission may elect to file an application seeking approval by the
5 Commission to construct a new electric generating facility, to
6 purchase an existing electric generation facility or enter into a long-
7 term contract for purchased power and capacity and/or
8 energy...shall be considered useful and its costs shall be subject to
9 cost recovery rules promulgated by the Commission...following
10 notice and hearing and **after consideration of reasonable**
11 **alternatives**. [Emphasis added.]

12 This section makes a crucial point: OG&E cannot recover the cost of a new build,
13 a long-term PPA, or the purchase of an existing generator without “consideration
14 of reasonable alternatives,” a showing they must make in a “hearing” at the
15 Commission.

16

17 **Q. What part of the Commission’s rules do you point to?**

18 A. I point to Chapter 35, Subchapter 35 of Title 165 – the Oklahoma Corporation
19 Commission’s Electric Utility Rules (“Commission Rules”) which states: “The
20 Commission shall conduct prudence reviews on all generation, purchased power
21 and fuel procurement processes and costs.”¹⁷ The Commission Rules go on to
22 state: “All fuel and generation expenses, including purchased-power-related
23 expenses, shall be reviewed by the Commission in adjudicatory proceedings to
24 determine that such expenses were prudently incurred. The utility shall bear the
25 burden of proof as to prudence.”¹⁸ The Commission Rules state later: “Nothing in

¹⁷ Commission Rules, 165:35-35-1(a).

¹⁸ Commission Rules, 165:35-35-1(b).

REDACTED

1 this Subchapter shall diminish the authority of the Commission to review for
2 prudence or other reasons any utility contract, decision or other action for the
3 provision of electric power capacity and energy.”¹⁹

4
5 This language makes it clear that OG&E’s Application for approval of its Mustang
6 modernization plan must satisfy a prudence review by the Commission.

7
8 **Q. Is a prudence review defined in more detail?**

9 **A.** Yes. The Commission’s rules state that Prudence Review:

10 means a comprehensive review that examines as fair, just, and
11 reasonable, a utility’s practices, policies, and decisions regarding an
12 investment or expense at the time the investment was made or
13 expense was incurred; including direct or indirect maximization of its
14 positive impacts and mitigation of adverse impact upon its
15 ratepayers, without consideration of its ultimate and useful nature.²⁰

16 Importantly, according to the Commission Rules, when making a showing of
17 prudence, a utility has two options. Option one is to obtain a “presumption of
18 prudence” from the Commission by “[employing] the competitive bidding
19 procedures” set forth in the Commission Rules “when purchasing or self-building
20 of new long-term electric generation, long term purchase power agreements, or
21 long-term fuel supply for self generation...”²¹ Option two abandons the
22 presumption of prudence by forgoing use of a competitive procurement and,

¹⁹ Commission Rules, 165:35-35-1(d).

²⁰ Commission Rules, 165:35-1-2.

²¹ Commission Rules, 165:35-34-1(a).

REDACTED

1 instead, allows “the determination of prudence” to be “decided during a subsequent
2 Commission review.”²²

3

4 **Q. Did OG&E conduct a competitive procurement?**

5 A. No. OG&E did not use a competitive procurement to secure a presumption of
6 prudence. Importantly, that does not excuse OG&E from considering competitive
7 alternatives to its proposed investments contained in its Application. On the
8 contrary, OG&E will still have to evaluate any reasonable alternatives, and is
9 required to do so in time for the Commission to make a finding in this hearing.

10

11 **Q. Are there any other points you would like to make regarding OG&E’s
12 decision to not conduct a competitive procurement?**

13 A. Yes. First, it is important to point out that although the Oklahoma Statutes provide
14 OG&E flexibility in submitting its Application by not requiring a competitive
15 procurement, the showing that OG&E must make pursuant to the statutes should
16 be equally rigorous in its consideration of all reasonable alternatives. Second, and
17 relatedly, if OG&E had conducted a competitive process and won, OG&E would
18 be held to cost caps.²³ OG&E’s decision to not conduct a competitive procurement
19 should not relieve it of its obligation to commit to certain cost and performance
20 standards to protect OG&E ratepayers.

²² Commission Rules, 165:35-34-1(a).

²³ For example, Commission Rules, 165:35-38(d) states: “If a Self-build Proposal is selected and approved by the Commission, the amount the soliciting utility shall recover through the rate base or other cost-recovery methods without additional Commission approval is limited to the total project cost identified in the Self-build Proposal.”

REDACTED

1

2 **B. OG&E WITNESSES IDENTIFY THE POWER PLANT UNITS AFFECTED AND**
3 **DESCRIBE THE ENVIRONMENTAL CONTROLS REQUIRED ON EACH OF**
4 **THEM**

5 **Q. What is your view on the basic information required for a complete filing by**
6 **OG&E?**

7 A. The most basic information would be to identify the power plant units affected and
8 to describe the environmental controls required at each unit.

9

10 **Q. Did OG&E meet the requirement?**

11 A. Yes. OG&E's witness Mr. Burch provides much of this information. Ms. Turner
12 also contributes.

13

14 **Q. Please summarize what Mr. Burch has to say?**

15 A. To start, Mr. Burch reports that MATS requires the control of emissions of mercury,
16 particulate matter ("PM"), and hydrogen chlorides ("HCl" or "acid gases") for two
17 coal-fired units at OG&E's Sooner site and for three coal-fired units at OG&E's
18 Muskogee site.²⁴ Sooner Units 1 and 2 are each about 500 MW and burn low
19 sulfur coal from the Powder River Basin.²⁵ Muskogee Units 1, 2, and 3 also are
20 about 500 MW each and also burn low sulfur coal from the Powder River Basin.²⁶

²⁴ Direct Testimony of Robert J. Burch on Behalf of Oklahoma Gas and Electric Company, Oklahoma Corporation Commission Cause No. PUD 201400229, filed August 6, 2014 ("Burch Direct Testimony"), page 2, lines 24 to 27.

²⁵ Burch Direct Testimony, page 3, lines 13 to 19.

²⁶ Burch Direct Testimony, page 3, lines 20 to 26.

REDACTED

1 Mr. Burch goes on to report that the RHR requires the control of emissions of sulfur
2 dioxide (“SO₂”) and nitrogen oxides (“NO_x”) at two coal-fired units at Sooner and
3 two at Muskogee as well as at three natural gas-fired units at OG&E’s Seminole
4 site.²⁷ The affected units at Seminole are three 500 MW units run on natural gas.²⁸

5

6 **Q. Are these significant requirements for OG&E?**

7 A. Yes. Mr. Burch notes that, together, these environmental compliance requirements
8 affect a significant share of the generating capacity that OG&E owns – 63 percent
9 of the capacity owned by OG&E is affected, 4,000 MW out of a total of 6,336 MW.²⁹

10

11 **Q. Does he discuss technological alternatives for compliance?**

12 A. Yes. Mr. Burch discusses OG&E’s proposed technological alternatives for meeting
13 the requirements of RHR and MATS. The RHR imposes restrictions on emissions
14 of both NO_x and SO₂ from OG&E. For NO_x emissions, OG&E must use the Best
15 Available Retrofit Technology or “BART”. This is defined as “installing low NO_x
16 burners (“LNB”) and over-fired air systems (“OFA”) on its seven Regional Haze-
17 affected generation units (and flue gas recirculation (“FGR”) on the affected gas
18 plants).”³⁰

19

20 **Q. What is the compliance date for this part of the RHR?**

²⁷ Burch Direct Testimony, page 2, lines 27 to 31.

²⁸ Burch Direct Testimony, page 3, lines 27 to 31.

²⁹ Burch Direct Testimony, page 3, lines 6 to 10.

³⁰ Burch Direct Testimony, page 4, lines 3 to 10.

REDACTED

1 A. The RHR NO_x compliance date is January 27, 2017.³¹

2

3 **Q. What are the RHR requirements for SO₂?**

4 A. For SO₂ emissions under the RHR – the subject of OG&E’s litigation with the U.S.
5 EPA – the applicable standard is the Federal Implementation Plan or “FIP”, which
6 requires a reduction of emissions to 0.06 lbs./MMBtu.³²

7

8 **Q. What is the compliance date?**

9 A. The compliance deadline for SO₂ emissions was pushed back because the FIP
10 was stayed while OG&E challenged it in court. That deadline is now January 4,
11 2019.³³

12

13 **Q. Does he discuss technological options for cutting SO₂ emissions?**

14 A. Yes. Mr. Burch discusses potential technologies for controlling SO₂ emissions. As
15 a backdrop, it is worth remembering that PSO was able to use the less expensive
16 dry sorbent injection (“DSI”) technology because it had settled with EPA and
17 agreed to retire its coal plants early to avoid installing the more expensive, but also
18 more effective, FGD technology, so-called “scrubbers.” Mr. Burch explains that
19 OG&E tested DSI technology at its plants and concluded that it could not meet the
20 sulfur dioxide removal standard set by the FIP (0.06 lbs/MMBtu).³⁴

21

³¹ Burch Direct Testimony, page 4, line 11.

³² Burch Direct Testimony, page 4, lines 12 to 15.

³³ Burch Direct Testimony, page 4, lines 16 to 20.

³⁴ Burch Direct Testimony, page 11, lines 14 to 20.

REDACTED

1 **Q. Do you agree?**

2 A. Yes. That is consistent with my understanding of the SO₂ removal capability of
3 DSI technology.

4

5 Mr. Burch then turns to discuss several varieties of FGD – again, Flue Gas
6 Desulfurization or “scrubbing” – technology, including those for “wet” and “dry”
7 FGD. He discusses four technologies for dry FGD – spray dryer absorber (“SDA”),
8 DSI, circulating dry scrubber (“CDS”), and a proprietary technology termed
9 NID™.³⁵ He uses SDA to show that dry FGD costs less than wet FGD.³⁶ He
10 rejects NID™ because of its “physical limitations and operational complexity.”³⁷
11 Additional analysis and site visits led OG&E to select “CDS as the FGD technology
12 to use.”³⁸

13

14 **Q. Does he estimate the cost of FGD?**

15 A. Yes. He reports that the capital cost estimate for CDS “for both Sooner units is
16 [REDACTED]” with an assumed accuracy of plus or minus 10 percent.³⁹ Mr. Burch
17 notes that this estimate was done internally at OG&E, but is in line with the costs
18 for SDA technology from a Sargent & Lundy study.⁴⁰ Mr. Burch reports that at the
19 time of his testimony, OG&E was evaluating bids from several vendors for CDS

³⁵ Burch Direct Testimony, page 11, lines 25 to 28.

³⁶ Burch Direct Testimony, page 10, lines 10 to 22 and Table 2.

³⁷ Burch Direct Testimony, page 11, lines 28 to 29.

³⁸ Burch Direct Testimony, page 12, line 11.

³⁹ Burch Direct Testimony, page 12, lines 23 to 26.

⁴⁰ Exhibit CRR-5, OG&E response to Data Request PUDKC 3-4(a).

REDACTED

1 equipment. CDS operation and maintenance costs are estimated to be \$30 million
2 per year assuming a 70 percent capacity factor.⁴¹

3

4 **Q. What about requirements for MATS?**

5 A. As noted, MATS requires control of emissions of mercury, PM, and HCl at coal-
6 fired units by April 16, 2016, which reflects a one-year extension allowed under
7 the regulation.⁴²

8

9 Mr. Burch reports that OG&E is already in compliance for PM and HCl emissions.⁴³

10 For mercury, however, Mr. Burch writes that OG&E must cut emissions about 80
11 percent and will use Activated Carbon Injection ("ACI") to meet the requirement.⁴⁴

12

13 **Q. What about the cost of ACI?**

14 A. Mr. Burch reports that ACI capital costs are \$9.7 million at Sooner with annual
15 operating costs of \$17.9 million. At Muskogee, the capital costs would be \$14.6
16 million and the annual operating costs are \$26.8 million.⁴⁵

17

18 **Q. Does Mr. Burch discuss alternatives to investing in control technology?**

⁴¹ Burch Direct Testimony, page 12, lines 37 to 39.

⁴² Burch Direct Testimony, page 4, line 24 to page 5 line 1.

⁴³ Burch Direct Testimony, page 15, lines 10 to 12.

⁴⁴ Burch Direct Testimony, page 15, lines 12 to 31.

⁴⁵ Burch Direct Testimony, page 16, lines 15 to 22.

REDACTED

1 A. Yes. Mr. Burch next discusses the conversion of coal-fired units to natural gas-
2 fired units. He notes that conversion of this sort can readily meet the SO₂ emission
3 limit set in the FIP.⁴⁶

4
5 Another approach to switching to natural gas is to replace the coal-fired units with
6 new natural gas-fired combined cycle plants. Mr. Burch notes that the capital cost
7 for such new units would be in the range of \$1,200 to \$1,440 per kW.⁴⁷

8
9 **Q. Did Mr. Burch discuss the alternative of a power purchase agreement?**

10 A. No. Mr. Burch makes no mention of the option of signing a power purchase
11 agreement with an existing or new natural gas-fired combined cycle plant as
12 conducted by PSO in its compliance proceeding.

13
14 **Q. Would you please summarize all this in terms of the MATS and RHR
15 requirements at each unit?**

16 A. Ms. Turner, another OG&E witness, provides a good summary of OG&E's
17 proposed compliance plan in her Chart 1, which is reproduced below as Figure
18 One.

⁴⁶ Burch Direct Testimony, page 13, lines 1 to 10.

⁴⁷ Burch Direct Testimony, page 13, lines 28 to 30.

**Figure One
Planned Compliance Actions with Regional Haze and MATS on Affected OG&E Units**

Units	MATS Compliance (Compliance Deadline)	Regional Haze Rule Compliance (Compliance Deadline)
Seminole Units 1, 2 & 3	N/A	NO _x : Low NO _x Burners/Over-fire Air (LNB/OFA) <i>(January 27, 2017)</i>
Sooner Units 1 and 2	Activated Carbon Injection System (ACI) <i>(April 16, 2016)</i>	NO _x : Low NO _x Burners/Over-fire Air (LNB/OFA) <i>(January 27, 2017)</i> SO ₂ : Dry Flue Gas Desulfurization (DFGD) <i>(January 4, 2019)</i>
Muskogee Units 4 and 5	Activated Carbon Injection System (ACI) <i>(April 16, 2016)</i>	NO _x : Low NO _x Burners/Over-fire Air (LNB/OFA) <i>(January 27, 2017)</i> SO ₂ : Conversion to Natural Gas <i>(January 4, 2019)</i>
Muskogee Unit 6	Activated Carbon Injection System (ACI) <i>(April 16, 2016)</i>	N/A

Source: Direct Testimony of Usha-Maria Turner, Cause No. PUD 201400229, Aug 6, 2014, p. 4, Chart 1.

1 **Q. Is this a significant effort by OG&E in terms of the resulting reduction of**
2 **emissions?**

3 **A.** Yes. Ms. Turner reports that the proposed compliance plan will have an important
4 impact on emissions. She finds that LNB will reduce NO_x emissions from coal by
5 50 percent. Dry FGD will cut SO₂ emissions from coal by 90 percent. And ACI will
6 cut mercury emissions from coal by 80 percent.⁴⁸ Conversion to natural gas would

⁴⁸ Direct Testimony of Usha-Maria Turner on Behalf of Oklahoma Gas and Electric Company, Oklahoma Corporation Commission Cause No. PUD 201400229, filed August 6, 2014 ("Turner Direct Testimony"), page 5, lines 10 to 13.

REDACTED

1 cut SO₂ emissions by 100 percent as compared to coal and would cut CO₂
2 emissions as compared to coal by 50 percent.⁴⁹

3

4 **C. OG&E PRESENTS THE METHODS AND RESULTS OF ITS EVALUTION OF**
5 **ALTERNATIVE COMPLIANCE OPTIONS**

6 **Q. Did OG&E evaluate alternative compliance plans?**

7 A. Yes. OG&E proposed and evaluated five alternative plans (“alternatives”) that they
8 believe would comply with EPA’s requirements under both RHR and MATS. Mr.
9 Howell, another OG&E witness, defined the five compliance alternatives. His
10 Figure 1 describing the five is reproduced below as Figure Two. Recall that
11 *Scrub/Convert* is the option that OG&E chose to propose to the Commission in this
12 proceeding.

⁴⁹ Turner Direct Testimony, page 5, lines 13 to 17.

REDACTED

Figure Two
OG&E's Proposed Environmental Compliance Plan Alternatives

Scrub/Convert	<ul style="list-style-type: none">• Scrub Sooner 1 by 2018 and Sooner 2 by 2019• Convert two Muskogee units by 2019
Scrub	<ul style="list-style-type: none">• Scrub Muskogee 4 by 2018 and Muskogee 5 by 2019• Scrub Sooner 1 by 2018 and Sooner 2 by 2019
Convert	<ul style="list-style-type: none">• Convert four coal units to gas by 2019
Scrub Replace	<ul style="list-style-type: none">• Scrub Sooner 1 by 2018 and Sooner 2 by 2019• Replace two Muskogee coal units with new CCs by 2019
Replace	<ul style="list-style-type: none">• Replace four coal units with new CCs by 2019

Source: Direct Testimony of Leon Howell, Cause No. PUD 201400229, Aug 6, 2014, p. 5, Figure 1.

1 **Q. What is the extent and nature of OG&E's evaluation of these five**
2 **compliance plans?**

3 **A.** In its 2014 Integrated Resource Plan, OG&E estimated the cost to customers for
4 each of the five proposed compliance alternatives under nine different sensitivity
5 runs. The results of this analysis – shown by OG&E in its Tables 19 and 20 – have
6 been combined in Table One below. These results are presented as the net
7 present value of customer costs (“NPVCC”) over a 30-year timeframe (2015-2044)
8 in billions of dollars.⁵⁰

⁵⁰ Note that OG&E also tests three future expansions plans for adding combined cycle and combustion turbine units to meet future capacity needs. OG&E finds that none of the three options has a significant impact on the NPVCC of any of the alternatives. However, the “Spread CT” expansion plan is found to consistently be the cheapest, by a small margin, so it is used in the Base Case sensitivity run. See OG&E 2014 IRP, page 43. All analysis discussed in Table One reflects an adjustment of one input to the Base Case assumptions.

REDACTED

Table One
30-year NPVCC for Each Alternative that OG&E Proposed under Nine Different Sensitivity Analyses
(Billions, 2014 Dollars)

	Scrub/Convert	Scrub	Convert	Scrub/Replace	Replace
Base	\$22.4	\$22.4	\$22.5	\$23.2	\$24.2
High Conversion	\$22.4	\$22.3	\$22.7	\$23.0	\$24.0
Low Conversion	\$22.2	\$22.4	\$22.2	\$23.3	\$24.3
High Gas	\$25.8	\$24.7	\$27.2	\$26.6	\$28.7
Low Gas	\$20.3	\$21.0	\$19.7	\$21.3	\$21.7
CO2	\$26.4	\$27.0	\$25.9	\$26.9	\$26.8
Low Load	\$22.1	\$22.4	\$22.0	\$23.2	\$24.2
High Capital Cost	\$23.6	\$23.9	\$23.6	\$25.0	\$26.3
Low Capital Cost	\$21.1	\$21.0	\$21.4	\$21.5	\$22.2
Average	\$22.9	\$23.0	\$23.0	\$23.8	\$24.7

Source: OG&E 2014 IRP, Table 19 on page 44 and Table 20 on page 46 (Average calculated by Boston Pacific).

REDACTED

1 **Q. What is the broad bottom line you take from these results?**

2 A. The results in Table One show that it was essentially a dead heat among the *Scrub*,
3 *Scrub/Convert*, and *Convert* alternatives. As shown in Table One above,
4 *Scrub/Convert* is tied for the cheapest alternative in three of the nine scenarios –
5 Base, Low Conversion, and High Capital Cost – but is never the cheapest alone.
6 OG&E's *Scrub* alternative is the cheapest alternative in three of the scenarios –
7 High Conversion, High Gas, and Low Capital Cost. Its *Convert* alternative is the
8 cheapest alternative in three of the scenarios – Low Gas, Low Load, and CO₂.

9

10 I added the last row in Table One, which is a simple average cost taken across all
11 nine sensitivities. The first three compliance alternatives are within \$0.1 billion
12 dollars – essentially tied.

13

14 **D. DEFICIENCIES MEAN OG&E'S EVALUATION PROCESS IS NOT SUFFICIENT**
15 **TO SUPPORT ITS COMPLIANCE PLAN AS-IS**

16 **Q. Is OG&E's evaluation sufficient to support its proposed compliance plan?**

17 A. No. I find five remaining deficiencies that mean OG&E has provided an incomplete
18 record for the Commission.

19

20 **Q. Is a complete record especially important here?**

21 A. Yes. A complete record is especially important here because OG&E's chosen
22 alternative – *Scrub/Convert* – is not the clear winner even if we accept OG&E's
23 proposed alternatives, assumptions, and methods for cost estimation.

REDACTED

1

2 **Q. Are you surprised by the absence of one clear winner?**

3 A. No. As explained above, this simply reflects uncertainty about the future. Also as
4 explained above, the standard recommendation is to diversify actions – as one
5 diversifies a stock portfolio. However, to identify the best portfolio of actions, a
6 complete assessment of alternative actions and uncertainties must be conducted.
7 It is in this sense that OG&E's recovery is incomplete because of deficiencies.

8

9 **Q. What is the first deficiency you discern?**

10 A. OG&E's first deficiency is that OG&E has not assessed existing capacity as an
11 option. They did not conduct an RFP to invite bids or even reach out to survey
12 existing generating plants in any systematic way. Specifically, OG&E was quite
13 clear that they did not seek out existing natural gas combined cycle units as an
14 alternative to scrubbing the Sooner units,⁵¹ did not conduct any competitive
15 solicitation to replace the Mustang units,⁵² and did not inquire about purchasing
16 the portions of the Redbud and McClain plants that OG&E does not already own.⁵³

⁵¹ In response to a data request that asked in part "Was executing a purchase power agreement or acquisition of an existing combined-cycle power plant evaluated as an alternative?" OG&E replied that it was "unaware of coal units being available for purchase power or acquisitions in the SPP territory; consequently, OG&E ruled out coal-based PPAs or acquisitions as an alternative to scrubbing the Sooner units." See Exhibit CRR-6, OG&E response to Data Request PUDKC 2-2.

⁵² OG&E witness Mr. Rowlett responds to the question "Did OG&E conduct a competitive solicitation for replacing the existing Mustang units in 2018?" with a simple "No." Direct Testimony of Donald R. Rowlett on Behalf of Oklahoma Gas and Electric Company, Oklahoma Corporation Commission Cause No. PUD 201400229, filed August 6, 2014 ("Rowlett Direct Testimony"), page 15, lines 23 to 25.

⁵³ See Exhibit CRR-7, OG&E response to Data Request PUDKC 1-7, which refers to OG&E potentially purchasing additional ownership stakes in the Red Bud or McClain plants by asking "why was such a purchase not considered?" OG&E did not reply by saying that they had investigated such a possibility but replied that its "partners have not expressed interest in selling their portions of the McClain and Redbud plants."

REDACTED

1 Additionally, OG&E assumed that its purchase power contracts at the Powersmith
2 and AES plants would not be renewed and did not seek to extend or replace them.
3 The only effort OG&E made was to receive one unsolicited offer for a combined
4 cycle unit and decide that it was lacking.⁵⁴

5

6 **Q. What is your biggest concern here?**

7 A. The biggest concern is that OG&E ignored existing natural gas generation units
8 that may be available. For example, my 2013 Responsive Testimony in the PSO
9 cause points to six different combinations of bids that met the minimum
10 requirements of PSO's RFP. That means that there were six qualified bidders to
11 supply capacity and energy in roughly the same time period as OG&E's current
12 capacity needs.⁵⁵ OG&E did not even attempt to identify or contact these or other
13 generators to see if any were still looking to sell. Instead, when asked in a data
14 request, OG&E simply stated that it was "aware of one [combined cycle] available
15 for acquisition in the region. This entity approached OG&E with an unsolicited
16 offer. OG&E is not aware of any other [combined cycle] in the region that would
17 be available for acquisition."⁵⁶ Again, PSO conducted an RFP at its own initiative
18 and succeeded in signing a PPA.

19

20 **Q. Has PSO issued a procurement more recently?**

⁵⁴ Exhibit CRR-8, OG&E response to Data Request Cogen 1-5.

⁵⁵ Roach Responsive Testimony in Cause No. PUD 201200054, page 59, Table 10.

⁵⁶ Exhibit CRR-8, OG&E response to Data Request Cogen 1-5.

REDACTED

1 A. Yes. PSO again issued on September 25, 2014 a short-term RFP for peaking
2 capacity and energy with delivery beginning June 1, 2016.⁵⁷ This indicates that
3 PSO continues to believe that the market is a viable option to meet its needs. This
4 is not only additional evidence that viable power purchase opportunities exist, but
5 that an RFP can be conducted to procure such resources in the timeframe that
6 OG&E needs them.

7
8 **Q. Can you be sure that any owners of existing natural gas generation units**
9 **would have been interested in participating in a RFP from OG&E?**

10 A. Yes. Using public information, my team found two serious bidders that OG&E
11 apparently never considered. My team called four entities known to have natural-
12 gas-fired generation in Oklahoma. They asked whether these entities would have
13 been able and willing to bid into a hypothetical OG&E RFP for natural gas-fired
14 combined cycle generation. Two entities, J-Power and LS Power, said that they
15 had a significant amount of capacity and energy available to market in the 2018
16 timeframe or earlier and most likely would have bid into such an RFP.⁵⁸

17
18 **Q. Is your survey of possible bidders meant to be a definitive study?**

⁵⁷ American Electric Power Service Corporation As Agent For Public Service Company of Oklahoma, "Request For Proposals Short-Term Peaking Capacity and Energy". Issued September 25, 2014 and revised September 29, 2014.

⁵⁸ J-Power said that they have an existing natural gas generating facility at their Green Country Energy site in Jenks, Oklahoma that could be expanded by 470 MW and ready to supply by 2018, if not sooner. They also said that they have about 800 MW of natural gas-fired supply that would be rolling off of contracts in 2022 and would be available to bid into an RFP for supply at that time. LS Power indicated that its Oneta Energy Center in Coweta, Oklahoma has at least 118 MW available for the period 2015 through 2018 and at least 488 MW available beginning in 2019. The Oneta site also has expansion possibilities that would take advantage of the existing infrastructure.

REDACTED

1 A. No. First, OG&E bears the burden of proving it has assessed reasonable
2 alternatives – by no means do I intend to relieve OG&E of that burden. My quick
3 outreach is meant only to prove OG&E has failed to even try.

4
5 Second, the only definitive “study” is a fair, open, and transparent competitive
6 procurement.

7
8 **Q. What is OG&E’s second deficiency?**

9 A. OG&E’s second deficiency is that it does not fully analyze the risk of new
10 environmental regulations that could shut down its newly retrofitted coal plants at
11 the Sooner site. This was a central issue in the PSO case that PSO itself raised.
12 The issue is this: would OG&E, after retrofitting coal units with scrubbers, get a full
13 30 years from those units, as OG&E assumes, or would OG&E have to retire them
14 early, perhaps after just 15 years, due to new environmental regulations. If the
15 OG&E coal units were assumed to run through 2044, scrubbers might look like a
16 good investment. If, instead, the coal units were forced to retire after just 15 years,
17 scrubbers might not look like a good investment on behalf of Oklahoma ratepayers.

18
19 To illustrate this risk, consider results from four recent studies. These studies show
20 that coal-fired units face substantial risk of retirement and that recent estimates
21 have tended to report an increase of the probability of coal retirements. First, the
22 Government Accountability Office (“GAO”) issued a report addressing, among
23 other things, the impact of EPA regulations on coal-fired generating unit

REDACTED

1 retirements. The GAO concludes that “planned retirements of coal-fueled
2 generating units appear to have increased and are above the high end of the
3 estimates we reported in July 2012.”⁵⁹ Specifically, the GAO found that its
4 “analysis indicates that power companies retired or plan to retire about 13 percent
5 of coal-fueled net summer generating capacity (42,192 MW) from 2012 through
6 2025, which exceeds the estimates of 2 to 12 percent of capacity we reported in
7 2012.”⁶⁰ Second, the U.S. EIA’s Annual Energy Outlook 2014 projected more coal-
8 fired generation retirements than did the EIA Annual Energy Outlook 2013.⁶¹ Third,
9 SPP conducted a reliability assessment of EPA’s 111(d) Clean Power Plan Rule.
10 SPP concluded that it would see about 9 GW of existing coal- and gas-fired
11 capacity retired to meet the Clean Power Plan Rule’s goals, about 6 GW more than
12 it had originally projected.⁶² Fourth, the Midcontinent System Operator (“MISO”)
13 released a study in September of this year that estimates the potential impact on
14 its generation fleet from EPA’s Clean Power Plan Rule. The MISO study
15 concluded that, on top of 12.6 GW of coal retirements projected through 2016, “up
16 to an additional 14 GW of coal capacity could be at risk for retirement.”⁶³ The
17 takeaway from these four studies is that recent, long-term forecasts of the life of

⁵⁹ “EPA Regulations and Electricity: Update on Agencies’ Monitoring Efforts and Coal-Fueled Generating Unit Retirements,” U.S. GAO, August 2014 (“GAO Report”), page 15.

⁶⁰ GAO Report, page 15.

⁶¹ In 2013, the EIA projected that there would be 273.0 GW of coal capacity in the electric power sector in 2020 (“Annual Energy Outlook 2013,” U.S. EIA, April 2013). In 2014, EIA projected that there would be 259.3 GW of coal capacity in the electric power sector in 2020, or 12 GW fewer than were projected the year before (“Annual Energy Outlook 2014,” U.S. EIA, April 2014).

⁶² “SPP assesses Clean Power Plan, says more time is needed to implement,” Southwest Power Pool, October 9, 2014, page 1.

⁶³ “GHG Regulation Impact Analysis – Initial Study Results,” MISO, September 17, 2014 at slides 3 and 13.

REDACTED

1 coal-fired generation – while anything but certain – are increasing the estimates of
2 coal plant retirements.

3

4 **Q. Does any OG&E data suggest that early retirements of its Sooner coal units**
5 **is an issue with possible impact here?**

6 A. Yes. Table Two is based on OG&E's own estimate of the cumulative customer
7 costs, year-by-year, for each scenario.⁶⁴ The highlighted cells in Table Two
8 indicate OG&E's proposed compliance alternative that has the lowest NPVCC up
9 to that point in time, according to OG&E's own analysis. See that the *Convert*
10 alternative is initially the cheapest alternative due to its low capital cost – up to
11 2035. However, due to its lower operating costs, the *Scrub/Convert* alternative
12 that uses coal eventually becomes the cheaper alternative on a NPV basis
13 thereafter.

⁶⁴ OG&E provided nominal, cumulative customer costs for each compliance alternative as well as a single 30-year NPV of customer costs. See Exhibit CRR-2, OG&E's response to Data Request OIEC 3-12, Attachment 86. I submitted Data Request PUDKC 4-1 (Exhibit CRR-9) to OG&E to calculate the NPV of customer costs by year, but OG&E did not do so. Instead, as shown in Table Two, Boston Pacific calculated the NPV of OG&E's nominal data using OG&E's weighted average cost of capital from its most recent rate case, 8.323 percent. The 30-year NPVCC are nearly identical to OG&E's 30-year NPVCC. Each of these calculated values in 2044 are no more than \$16 million, or 0.07 percent different from OG&E's calculation. That is, any discrepancy does not change the conclusion that I draw from this table.

REDACTED

Table Two
NPVCC, Selected Years, Base Case (\$2014 Millions)

	Scrub / Convert	Scrub	Convert	Scrub / Replace	Replace
2015	1,074	1,078	1,069	1,084	1,090
2020	6,259	6,390	6,143	6,625	6,881
2025	10,825	11,062	10,656	11,504	12,019
2030	14,576	14,816	14,440	15,388	16,070
2035	17,718	17,898	17,675	18,569	19,382
2040	20,428	20,536	20,483	21,293	22,215
2044	22,344	22,415	22,476	23,218	24,221

Source: underlying data come from OG&E's response to data request OIEC 3-12, Attachment 86 (Exhibit CRR-2); Calculations by Boston Pacific.

1 **Q. What is your bottom line?**

2 A. My bottom line is that if the Sooner coal units with FGD are forced to retire early –
3 by about 2035 or earlier – *Scrub/Convert* will not be the cheapest of OG&E's
4 proposed alternatives. Additionally, Table Two is just indicative of this; it does not
5 give the full picture. It does not show (a) the impact of stranded cost recovery in
6 2035 or earlier, or (b) the cost of replacing power from the retrofitted coal units at
7 Sooner starting in 2035 or sooner.

8
9 **Q. What is OG&E's third deficiency?**

10 A. OG&E's third deficiency is that it has not fully analyzed sensitivities of its own load.
11 As I understand it, OG&E's load sensitivity involved a 10 percent reduction in
12 SPP's load, which, in turn, led to lower SPP market prices. The sensitivity run did
13 not lower OG&E's load – it just lowered SPP market prices. Equally important,
14 OG&E never even attempted a high load sensitivity.

REDACTED

1

2 So OG&E did not conduct any assessment of the possible effect of a decrease or
3 increase in demand on its choice of compliance option. It seems clear that lower
4 load could obviate the need for, say, converted capacity at Muskogee. Or higher
5 load might have tipped the scale in favor of replacement with combined cycle.

6

7 To provide such an assessment here, we asked OG&E in data requests and a
8 phone call to conduct sensitivities of its own load, higher and lower, but it chose
9 not to.⁶⁵ We also asked if OG&E had conducted industry-specific load surveys.
10 OG&E reported that it had not.⁶⁶

11

12 **Q. What is OG&E's fourth deficiency?**

13 A. OG&E's fourth deficiency is that its sensitivity analyses vary just one input at a
14 time.⁶⁷ We are concerned that such analyses are too simplistic to reasonably
15 estimate the costs of OG&E's proposed compliance alternatives under real-world
16 scenarios.

17

18 For example, OG&E runs separate sensitivities with higher natural gas prices and
19 with a CO₂ tax, but no combination sensitivities with both high natural gas prices
20 and CO₂ tax. The two could likely come together since a CO₂ tax would shift
21 demand away from coal and to natural gas, raising its price. We asked for such a

⁶⁵ Exhibit CRR-10, OG&E Response to Data Request PUDKC 1-6(b).

⁶⁶ Exhibit CRR-11, OG&E Response to Data Request PUDKC 3-6(b).

⁶⁷ OG&E 2014 IRP, page 46.

REDACTED

1 run through data requests and in a phone call with OG&E, but OG&E chose to not
2 run it, simply stating "OG&E has not analyzed a situation where both high natural
3 gas and CO2 costs both occur at the same time."⁶⁸

4
5 Similarly, we submitted a data request asking for a more complex sensitivity that
6 would serve as a high-environmental-policy test case. This sensitivity would have
7 a CO₂ tax, high natural gas prices, high conversion of SPP coal units to natural
8 gas, and an assumption that OG&E's Sooner coal units are forced to retire in
9 2031.⁶⁹ We explained our reasoning and again asked for this sensitivity on a call
10 with OG&E, but OG&E chose not to provide it.

11
12 **Q. Is it reasonable for a utility to run this type of combination sensitivity?**

13 A. Yes. To pick just one example of a recent utility planning exercise that did just
14 this type of sensitivity, see the 2014 IRP of Public Service Company of New
15 Mexico ("PNM"). PNM included both "Low Gas / Low Carbon" and "High Gas /
16 High Carbon" sensitivities as part of its analysis.⁷⁰

17
18 **Q. Have you recommended and conducted multi-factor sensitivities for other
19 regulatory commissions?**

20 A. Yes. One important example is our work on the evaluation of a proposed clean
21 coal project for the Mississippi Commission. Boston Pacific evaluated the project

⁶⁸ Exhibit CRR-12, OG&E response to Data Request PUDKC 3-1.

⁶⁹ Exhibit CRR-13, OG&E response to Data Request PUDKC 4-6(a).

⁷⁰ "PNM Draft Integrated Resource Plan 2014 – 2033", July 2014, page 69.

REDACTED

1 – the Kemper County Integrated Combined Cycle (“Kemper”) – and also invited
2 competing bids from existing and new natural gas-fired combined cycle plants.
3

4 This was a multi-factor evaluation. First, the alternatives (Kemper or the bids) were
5 evaluated under five different natural gas price forecasts and four different CO₂
6 allowance prices, so every matrix of results had 20 scenarios within it. Then other
7 factors were varied in combination to create matrices of additional results. A total
8 of 30 matrices – containing 600 scenarios in total – were presented to the
9 Mississippi Commission. The matrices varied by these factors: the analytic
10 method for evaluating shorter-term bids; whether fixed natural gas-priced bids
11 were considered; whether longer-term bids were preferred; whether a location in
12 Mississippi was required; and whether capital costs for Kemper were as forecast,
13 10 percent higher, or 20 percent higher.⁷¹
14

15 **Q. Did the Mississippi Commission use these multi-factor sensitivities in its**
16 **final order?**

17 **A.** Yes. In its final order, the Mississippi Commission used the matrices to specify
18 that (a) overall, the Kemper option won the competition, and (b) a cap on capital
19 costs would be set for Kemper based on one of the matrices.⁷²
20

⁷¹ Report of the Independent Evaluator in Docket No. 2009-UA-0014 (Redacted Public version),
Mississippi Public Service Commission, filed January 25, 2010 (“Kemper Report”);

⁷² *Final Order on Remand Granting a Certificate of Public Convenience and Necessity, Authorizing
Application of Baseload Act, and Approving Prudent Pre-Construction Costs*, Mississippi Public Service
Commission, Docket No. 2009-UA-014, April 24, 2012.

REDACTED

1 **Q. Are there other ways in which OG&E's sensitivities are overly simplistic?**

2 A. Yes. Another example of how OG&E's simplistic single-factor sensitivity analyses
3 may bias its results can be seen by considering OG&E's "High Conversion"
4 sensitivity in which many utilities convert their coal units to natural gas, and market
5 energy prices are higher. In that sensitivity, OG&E's coal units look strong
6 because they make a lot of money when SPP market prices are high. This ignores
7 the fact that the initial assumption of the sensitivity is that many others with coal
8 plants in SPP had a good motive to convert their coal units – perhaps in anticipation
9 of more strict environmental regulations. If there was a good reason for other SPP
10 market participants to convert their coal units, why would OG&E not face that same
11 motive, too? This needs to be explained.

12

13 **Q. What is OG&E's fifth deficiency?**

14 A. OG&E's fifth deficiency is that its analysis relies on possibly optimistic forecasts of
15 SPP energy market prices to support its choice to convert its Muskogee coal units
16 4 and 5 to natural gas. If OG&E's market price forecasts are too low, that could
17 bias its decision towards those compliance alternatives such as *Convert* that rely
18 more heavily on SPP market purchases.

19

20 **Q. Does your review of OG&E analyses support this concern?**

21 A. Yes. Again, OG&E would rely on the SPP market more under its compliance
22 alternatives that involve converting its coal units to natural gas than under other
23 alternatives. To quantify this reliance on the SPP market, we can compare how

REDACTED

1 many MWh OG&E buys from the market, on net, under the (a) *Scrub/Convert*
2 alternative and (b) the *Replace* alternative. Under its base case assumptions,
3 looking at just the year 2020, OG&E's energy need is 30,810,712 MWh. Under
4 the *Replace* option, OG&E will generate 28,164,698 MWh, which means that, on
5 net, it will purchase 2,646,014 MWh, or about 9 percent of its total energy needs.
6 However, under its chosen *Scrub/Convert* alternative, OG&E will generate just
7 22,570,098 MWh, buying on net 8,240,614 MWh or some 27 percent of its total
8 load – three times as much.

9

10 **Q. Is there other evidence that supports this concern?**

11 A. Yes. OG&E's own witness, Mr. Reed, cautioned against over-reliance on forecasts
12 of SPP market prices. Mr. Reed stated that "Projections of SPP market prices
13 depend on the actions of every single SPP generation owner and an implicit
14 assumption that the market design will not change in the future. In my mind, this
15 is even more speculative than trying to project natural gas prices and the timing,
16 form and market impacts of future carbon regulation."⁷³

17

18 **Q. What about data indicating OG&E's forecast of SPP market prices could be**
19 **too low?**

20 A. To start, note that OG&E assumes that it will build new combined cycle capacity
21 as early as 2018. The issue is whether SPP market prices are high enough to

⁷³ Direct Testimony of John J. Reed on Behalf of Oklahoma Gas and Electric Company, Oklahoma Corporation Commission Cause No. PUD 201400229, filed August 6, 2014 ("Reed Direct Testimony"), page 26, lines 22 to 25.

REDACTED

1 justify that investment – that is, does the revenue earned at those prices cover the
2 full cost of building and operating this new combined cycle capacity. If not, OG&E's
3 assumption that new combined cycles are built is inconsistent with its market price
4 forecast.

5

6 **Q. Did you address the issue quantitatively?**

7 A. Yes. The steps I took are as follows. First, I estimated how often a new combined
8 cycle plant would be dispatched by SPP; I did this by assuming that the unit would
9 run if its fuel and other variable costs per MWh were lower than the SPP market
10 price in that hour. Under OG&E's base case assumptions for SPP market prices,
11 natural gas prices, and combined cycle heat rate, I estimated that the unit would
12 be dispatched 69 percent of the time, on average, over the period 2018 through
13 2044.⁷⁴

14

15 Second, I computed the revenue earned by that combined cycle unit in the SPP
16 energy market in all the hours it was dispatched.

17

18 Third, I deducted from that revenue the fuel and other variable costs of the unit.
19 With that deduction, I am left with the dollars remaining to cover the capital and
20 other fixed costs of the combined cycle unit – these dollars are often called the
21 "margin." If the margin equals or exceeds the capital and other fixed costs of the

⁷⁴ OG&E's forecasts for SPP energy prices were presented in OG&E's Response to Data Request Sierra Club 1-37_Att 1 (Exhibit CRR-14). OG&E's natural gas price forecasts were presented in OG&E's Response to Data Request OIEC 1-25_Att 1 (Exhibit CRR-15).

REDACTED

1 combined cycle units, the investment is justified by these market prices. If the
2 margin falls short of this, the investment in a new combined cycle is not justified.

3

4 **Q. What did you find?**

5 A. I found that the margin was not sufficient to justify the investment; it covered only
6 about one-third of the unit's fixed costs. This suggests that OG&E's base case
7 forecast of SPP market prices is too low to be consistent with OG&E's assertion
8 that combined cycle units will be built.

9 **Q. By how much would SPP market prices have to rise?**

10 A. My analysis suggests OG&E's base case SPP energy market price forecast would
11 have to rise about one-third – even as natural gas prices remain constant – to
12 justify the construction of a new combined cycle unit.

13

14 **Q. Is your analysis equivalent to OG&E's "High Gas" scenario?**

15 A. No. My analysis just tests the consistency between (a) OG&E's assertion that new
16 combined cycle units would be built, and (b) OG&E's Base Case SPP market
17 prices. It does that at a given natural gas price; with higher natural gas price
18 assumptions, the unit's fuel cost would rise and, thereby, its margin would fall.

19

20 **IV. OG&E'S EVALUATION OF ALTERNATIVES FOR ITS MUSTANG**
21 **MODERNIZATION PLAN ALSO IS DEFICIENT**

REDACTED

1 **Q. What is your overall conclusion of OG&E's evaluation of alternatives for its**
2 **Mustang modernization plan?**

3 A. My overall conclusion is that OG&E failed to assess reasonable alternatives to its
4 plan for the Mustang site. OG&E only fully considered the replacement of the
5 existing Mustang units with new combustion turbines at the Mustang site built by
6 OG&E. It never fully evaluated combined cycle units, new and existing, at the
7 Mustang site or at other equally reliable sites. And it never assessed the possibility
8 of other power developers offering a better deal to Oklahoma ratepayers.

9

10 **Q. Did OG&E attempt to justify its limited review of alternatives?**

11 A. Yes, at least indirectly. However, I do not find any of its justification to be
12 compelling. I discern three attempted justifications. The first is that the Mustang
13 site is uniquely reliable as a location for capacity.⁷⁵

14

15 **Q. Is that accurate?**

16 A. No. In SPP, all sites that can secure Network Resource status meet the same
17 reliability test. In a response to a data request OG&E seems to acknowledge this
18 fact. Specifically, in response to a data request asking: "Is it OG&E's opinion that
19 the network resources at the Mustang site are somehow more important to system
20 reliability than network resources at all other OG&E sites?" Mr. Burch and Mr.
21 Howell respond: "All of OG&E's resources are important for system reliability.
22 OG&E does not believe that any one generating resource is more important than

⁷⁵ Howell Direct Testimony, page 21, lines 26 to 29.

REDACTED

1 its other units.” Further, Mr. Burch and Mr. Howell also state that “combustion
2 turbines located at another site could provide system reliability benefits
3 comparable to the benefits of combustion turbines at the Mustang site.”⁷⁶

4
5 OG&E also hinted that Mustang made a unique contribution to reliability because
6 of its proximity to the Tinker Air Force Base.⁷⁷ OG&E’s response seems to agree
7 that this was not accurate either. For example, OG&E also acknowledged that
8 they have “not assessed whether Tinker AFB has additional backup power to
9 supply a load island.”⁷⁸

10
11 **Q. What is OG&E’s second attempted justification?**

12 A. OG&E’s second attempt to justify the limited review of alternatives was to suggest
13 that the Mustang units would suffer greater failures under the new market
14 commitment and dispatch regimes in SPP’s new Integrated Marketplace.⁷⁹ That
15 is, these units would be started and stopped more frequently, which would lead to
16 more equipment failures. In this regard, I note that the 2014 IRP assumes that the
17 Mustang units start up significantly less than did the 2012 IRP. For example,
18 whereas the 2012 IRP assumed that Mustang units 2, 3 and 4 would start up a
19 total of 77 times in 2017, the 2014 IRP assumes just 12 starts.⁸⁰ This indicates
20 that there was forecast to be significantly less wear and tear on the units now than

⁷⁶ Exhibit CRR-3, OG&E’s Response to Data Requests PUDKC 3-8(b) and 3-8(c).

⁷⁷ OG&E 2014 IRP, p. 27.

⁷⁸ Exhibit CRR-3, OG&E’s Response to Data Request PUDKC 3-8(e).

⁷⁹ Burch Direct Testimony, page 20, lines 18 to 24.

⁸⁰ Exhibit CRR-4, OG&E’s Response to Data Request PUDKC 3-9, Att 2.

REDACTED

1 previously expected, when the units were to be retired more slowly. Additionally,
2 while the 2012 IRP forecast 132 starts for the Mustang units in 2014, actual starts
3 are no higher – just 104 so far in 2014, as per a November 10, 2014 data request
4 from OG&E.⁸¹ This indicates that the additional wear and tear that OG&E is
5 worried about is not actually occurring.

6
7 **Q. What is OG&E's third attempt?**

8 A. OG&E's third attempt to justify the limited review of alternatives was that the
9 replacement had to be done in a hurry. We note however that, in its 2012 IRP,
10 OG&E recommended much slower retirement of the Mustang capacity.⁸² Under
11 its Mustang modernization plan, OG&E would retire one Mustang unit in 2015 and
12 the three other units in 2017. Compared to the 2012 IRP, this is an increased pace
13 of retirements. OG&E sped up the retirement of Unit 3 (121 MW) by 3 years, from
14 the end of 2020 to the end of 2017, and Unit 4 (242 MW) by 7 years, from the end
15 of 2024 to the end of 2017. OG&E fails to provide any compelling reasons for this
16 proposed acceleration of retirements for the Mustang units.

17
18 **Q. What is the right way to review the full range of reasonable alternatives for**
19 **the Mustang site?**

20 A. The right way to evaluate the full range of reasonable alternatives for the Mustang
21 site is to conduct a competitive procurement for that replacement.

⁸¹ Exhibit CRR-4, OG&E's Response to Data Request PUDKC 3-9, Att 1.

⁸² OG&E 2012 IRP, p. 28.

REDACTED

1

2 **Q. Is there time for that?**

3 A. Yes. Let's assume the 2012 schedule of retirements is put back in place. Surely
4 existing capacity can be procured to replace any of the four capacity retirements.

5 New capacity could serve to replace the three later dates – those three account
6 for almost 90 percent of the power capacity. Even if OG&E thinks it needs more
7 time, it could negotiate an extension of the contracts with the two qualifying
8 facilities that OG&E now assumes are not renewed or conduct a competitive
9 solicitation for a short-term purchase of capacity and energy – as PSO is now
10 doing. Note that PSO's long-term competitive procurement related to its
11 environmental compliance plan took less than six months.

12

13 **Q. How far into the future could OG&E defer its capacity need?**

14 A. Table Three shows the lessening and deferral of capacity's need by two possible
15 actions.

**Table Three
Alternative Estimates of Capacity Need**

		2018	2019	2020	2021	2022	2023	2024
1	Capacity Need per 2014 IRP	289	336	460	488	532	905	1,134
2	Capacity Need Assuming Mustang Retirements per 2012 IRP	-	-	97	246	290	663	892
3	Capacity Need Assuming Extend or Replace Purchase Power Contracts	289	334	338	366	410	463	692
4	Capacity Need Assuming Mustang Retirements per 2012 IRP and Extend or Replace Purchase Power Contracts	-	-	-	124	168	221	450

Source: OG&E 2014 IRP; Calculations by Boston Pacific.

REDACTED

1 Row 1 shows OG&E's estimate of capacity need – the earliest need is for 289 MW
2 in 2018. Row 2 shows capacity need if the Mustang units are retired more slowly,
3 as in OG&E's 2012 RFP. With this slower pace, the capacity need is deferred
4 entirely by two years to 2020 and is lessened in that year to just 97 MW. Row 3
5 shows the effect of extending the two qualifying facility contracts. Row 4 shows
6 the effect of combining both the slower pace of Mustang retirements and the
7 extended QF contracts. With the combination in Row 4, the capacity need is
8 deferred to 2021 and lessened to 124 MW in that year.

9
10 **Q. Are there any other reasons that you find OG&E's justifications for action on**
11 **its Mustang units deficient?**

12 A. Yes. Even if OG&E did not conduct a competitive procurement to replace its
13 Mustang units, OG&E should have done what it could to postpone the retirement
14 of these units. As previously noted, the RHR and MATS require action on 63
15 percent of OG&E's capacity, 4,000 MW out of a total of 6,336 MW. This alone
16 imposes significant cost increases and risk on ratepayers. At this time OG&E
17 should be trying to minimize additional capital investment and risk, not increase it.

18
19 **V. OG&E'S RATE RECOVERY PROPOSAL PUTS TOO MUCH RISK ON THE**
20 **SHOULDERS OF RATEPAYERS**

21 **Q. Is OG&E's proposal in the instant cause a full rate filing under the**
22 **Commission's rules and regulations?**

REDACTED

1 A. No. OG&E states that, “OG&E intends to meet the requirements of 17 O.S. 286,
2 which states that a utility is required to ‘file a request for review of its rates pursuant
3 to Section 152 of this title no more than twenty-four (24) months after the utility
4 begins recovering the costs through a periodic rate adjustment mechanism.’
5 OG&E has indicated its intention to file a rate case after the conclusion of this
6 cause.”⁸³

7
8 **Q. While not a full rate filing, does OG&E’s proposal include a plan for rate
9 recovery of costs associated with the environmental compliance plan and
10 Mustang modernization plan?**

11 A. Yes. OG&E witness Ms. Richard provides details on “OG&E’s request to recover
12 both the costs to comply with the Regional Haze and the Mercury and Air Toxics
13 Standards rules and the costs to modernize the Mustang facility...”⁸⁴

14
15 **Q. Please provide an overview of OG&E’s rate recovery proposal.**

16 A. OG&E proposes to recover costs through “a periodic rate adjustment mechanism
17 called the Environmental and Generation Plan (“EGP”) rider and through OG&E’s
18 Fuel Cost Adjustment rider,” or “FAC.”⁸⁵ OG&E is requesting “a return on and
19 recovery of the capital investment and recovery of other expenses through the
20 EGP rider and the air quality control systems consumables (“AQCS”) costs

⁸³ Exhibit CRR-16, OG&E response to Data Request OER 2-3.

⁸⁴ Direct Testimony of Sheri Richard on Behalf of Oklahoma Gas and Electric Company, Oklahoma Corporation Commission Cause No. PUD 201400229, filed August 6, 2014 (“Richard Direct Testimony”), page 1, lines 21 to 23.

⁸⁵ Richard Direct Testimony, page 1, lines 23 to 25.

REDACTED

1 recovery through the FAC for the environmental compliance plan and Mustang
2 plant modernization projects.”⁸⁶

3

4 **Q. Please describe the purpose of the EGP rider.**

5 A. The EGP rider is provided in Ms. Richard’s testimony as Exhibit SDR-2. The
6 purpose of the EGP rider is “to recover the Oklahoma retail jurisdictional portion of
7 the annual revenue requirement for expenditures related to environmental
8 compliance projects and generation plan modernization projects.”⁸⁷

9

10 **Q. Has OG&E proposed a total capital investment related to its proposal that
11 will determine OG&E’s revenue requirement?**

12 A. OG&E has provided an estimate of its total capital investment through 2019. That
13 figure is \$1.0871 billion.⁸⁸

14

15 **Q. Has OG&E provided an estimate of the customer impact of the EGP rider on
16 its ratepayers?**

17 A. OG&E provided estimates for the 2015 through 2044 timeframe, including fuel. In
18 2019, for example, the year in which the EGP rider and related changes in fuel
19 costs are estimated to have their largest impact on OG&E customers, the average
20 estimated monthly bills for OG&E’s customers are as follows, by rate class: (a)
21 Residential customers’ monthly bills are expected to rise by \$7.26/month, an

⁸⁶ Richard Direct Testimony, page 2, lines 11 to 14.

⁸⁷ Richard Direct Testimony, Exhibit SDR-2, page 1.

⁸⁸ Rowlett Direct Testimony, page 16, Chart 2.

REDACTED

1 increase of 6.18 percent from 2018 levels; (b) General Service customers' monthly
2 bills are expected to rise by \$12.16/month, an increase of 6.06 percent from 2018
3 levels; (c) Power & Light customers' monthly bills are expected to rise by
4 \$240.24/month, an increase of 7.40 percent from 2018 levels; and (d) Large Power
5 & Light customers' monthly bills are expected to rise by \$20,265.32/month, an
6 increase of 8.80 percent from 2018 levels.⁸⁹

7

8 **Q Does the EGP rider – the mechanism by which OG&E recover its capital**
9 **investment – hold OG&E to a firm cap on the amount it can recover through**
10 **the rider?**

11 A. No. Section A of the proposed EGP rider states: "All project expenditures made
12 by [OG&E] and not recovered in existing approved base rates shall be recovered
13 as part of this rider."⁹⁰ The rider will "remain in effect until terminated by order of
14 the Commission,"⁹¹ and as explained by OG&E, "[w]hen approved, the EGP rider
15 will ... continue until all approved EGP rider costs are included in base rates."⁹²

16

17 **Q. Please describe the applicability of the EGP rider.**

⁸⁹ Exhibit CRR-17, OG&E response to Data Request OIEC 3-2 shows the incremental annual customer impact through 2044. The annual percentage change in rates was calculated by Boston Pacific and assumes a base monthly bill that the first incremental bill impact provided by OG&E in its response to Data Request OIEC 3-2, for 2015, is incremental to the "Average Monthly Bill" provided by OG&E in that same data request.

⁹⁰ Richard Direct Testimony, Exhibit SDR-2, page 2.

⁹¹ Richard Direct Testimony, Exhibit SDR-2, page 1.

⁹² Richard Direct Testimony, page 3, lines 26 to 28.

REDACTED

1 A. The EGP rider is applicable “to all Oklahoma retail rate classes and customers
2 except those specifically exempted by special contract.”⁹³ The EGP rider will be
3 allocated to OG&E customers using “the most recently approved production
4 demand allocation factor.”⁹⁴ For example, Residential customers will be allocated
5 approximately 47 percent of the EGP rider.⁹⁵

6

7 **Q. Does OG&E specify how much investment will be recovered through the
8 EGP rider?**

9 A. No. However, the EGP rider will be used to recover a “substantial” amount of
10 costs; specifically, OG&E states that the “proposed capital costs to comply with the
11 CAA requirements and for the Mustang plant modernization is approximately \$1
12 billion.”⁹⁶

13

14 **Q. What is the effective term of the EGP rider?**

15 A. The EGP rider “will be implemented the first billing cycle of the month following
16 Commission approval of the EGP and shall remain in effect until terminated by
17 order of the Commission.”⁹⁷ Additionally, the EGP rider states that “[a]ll project
18 expenditures made by [OG&E] and not recovered in existing approved base rates
19 shall be recovered as part of [the EGP rider].”⁹⁸

20

⁹³ Richard Direct Testimony, Exhibit SDR-2, page 1.

⁹⁴ Richard Direct Testimony, Exhibit SDR-2, page 2.

⁹⁵ Richard Direct Testimony, Exhibit SDR-2, page 2.

⁹⁶ Richard Direct Testimony, page 2, lines 21 to 23.

⁹⁷ Richard Direct Testimony, Exhibit SDR-2, page 1.

⁹⁸ Richard Direct Testimony, Exhibit SDR-2, page 2.

REDACTED

1 **Q. Will OG&E wait to begin charging its customers for capital investment**
2 **related to the environmental compliance plan and Mustang modernization**
3 **plan until the Mustang, Muskogee, and Sooner investments are fully in**
4 **service, with all conversion, construction, or other environmental retrofits**
5 **complete?**

6 A. No. As noted above, OG&E will implement the EGP rider in the first billing cycle
7 after the Commission issues an order approving OG&E's proposals in the instant
8 cause.

9

10 **Q. Is there a rate treatment that OG&E seeks that would allow it to charge**
11 **customers for facilities that are not yet in service?**

12 A. Yes. OG&E seeks Construction Work in Progress rate treatment, or "CWIP."

13

14 **Q. Please describe CWIP.**

15 A. CWIP is an accounting and ratemaking procedure that allows for the recovery of
16 financing expenses on construction work in progress. Construction costs are
17 entered into rate base as they are incurred (or as adjustments to historic test years)
18 so that investments begin to earn their allowed return without delay.⁹⁹

19

20 **Q. Does CWIP provide any benefits to OG&E?**

⁹⁹ Edison Electric Institute, "New Regulatory Frameworks for Electric Infrastructure Investment," available at http://www.eei.org/issuesandpolicy/stateregulation/Documents/altreg_brochure_final.pdf.

REDACTED

1 A. Yes. CWIP allows OG&E to recover a return earlier than it otherwise would under
2 the traditional rate recovery mechanism of Allowance for Funds Used During
3 Construction, or AFUDC. This can help sustain OG&E's financial condition during
4 periods of large capital investments.

5

6 **Q. Does CWIP provide any benefits to OG&E's ratepayers?**

7 A. The proffered benefit is that CWIP gives the appearance of lower rate increases
8 as compared to the use of AFUDC.¹⁰⁰ CWIP also can potentially provide a benefit
9 to OG&E's ratepayers if OG&E is able to secure lower-cost financing for the
10 environmental compliance plan. In theory, by allowing OG&E to recover its
11 construction financing costs earlier, OG&E's financial condition would be
12 improved, and OG&E may be able to obtain more favorable terms for its debt
13 financing. However, this impact would be hard to quantify.

14

15 **Q. What is the first step in calculating the EGP rider?**

16 A. The rider is calculated by first determining the average capital investment, which
17 is the capital expenditures made in a given year plus any prior year expenditures
18 on environmental control equipment, combustion turbines, preliminary survey and
19 investigation costs, and infrastructure expenditures such as roads, buildings, and
20 railways.¹⁰¹ The average capital investment is then multiplied by the Commission-

¹⁰⁰ Rowlett Direct Testimony, page 17, lines 3 to 11.

¹⁰¹ Richard Direct Testimony, page 8, lines 3 to 6.

REDACTED

1 approved rate of return for OG&E.¹⁰² Prior to the in service date for each asset,
2 this step will calculate CWIP, after that it calculates return on investment.

3

4 **Q. What is the second step in calculating the EGP rider?**

5 A. The return calculated in step one is then added to O&M expenses, depreciation,
6 and property taxes.¹⁰³ O&M includes incremental costs for labor, insurance,
7 utilities, and materials.¹⁰⁴ Depreciation is the portion of the total capital cost
8 recovered each year – including capital costs for emission control technology and
9 the new Mustang combustion turbines – beginning when the assets are placed into
10 service.¹⁰⁵ Property tax assumes a 1 percent property tax calculated on the capital
11 investment at the beginning of each year.¹⁰⁶ OG&E states that “any property taxes
12 that are or will be recovered through the EGP rider during the test year including
13 any pro forma period will be excluded from pro forma operating expense” for
14 subsequent base rate cases.¹⁰⁷

15

16 **Q. What is the third step in calculating the EGP rider?**

17 A. The third step is to add amortization of two newly-created regulatory assets, both
18 of which are proposed by OG&E. The first regulatory asset is stranded capital cost
19 related to coal handling and processing and ash disposal equipment for Muskogee
20 units 4 and 5 and is estimated to be \$35.6 million. OG&E proposes to recover this

¹⁰² Richard Direct Testimony, page 6, lines 25 to 27.

¹⁰³ Richard Direct Testimony, page 6 line 28 to page 7 line 1.

¹⁰⁴ Richard Direct Testimony, page 9, lines 28 to 30.

¹⁰⁵ Richard Direct Testimony, page 10, lines 6 to 11.

¹⁰⁶ Richard Direct Testimony, page 10, lines 15 to 16.

¹⁰⁷ Exhibit CRR-18, OG&E response to Data Request OIEC 4-9.

REDACTED

1 regulatory asset over six years beginning in 2018.¹⁰⁸ The second regulatory asset
2 is an estimated \$0.5 to \$1 million in one-time O&M costs for witness fees,
3 consulting, and legal fees related to OG&E's environmental compliance plan
4 during 2014 and 2015. OG&E proposes to recover these costs over two years
5 beginning in 2015.¹⁰⁹

6
7 **Q. Describe the fourth step in calculating the EGP rider.**

8 A. The fourth and final step in calculating the EGP rider is to sum the items in the first
9 three steps to produce OG&E's annual revenue requirement, which is then
10 multiplied by the demand allocation factors to determine the monthly charge to
11 each of OG&E's ratepayer classes under the EGP rider.¹¹⁰

12
13 **Q. Describe the costs to be recovered by the EGP rider in 2015, as proposed by**
14 **OG&E.**

15 A. OG&E proposes to recover an estimated \$13.8 million in 2015 under the EGP rider
16 related solely to CWIP return.¹¹¹ That is, OG&E will recover its Commission-
17 approved rate of return of 11.7 percent¹¹² on its Average Capital Investment of
18 \$117.8 million in 2015; that total is \$13.8 million.¹¹³ In addition, OG&E proposes
19 to recover \$1.1 million in depreciation in 2015 related to the LNB equipment and

¹⁰⁸ Richard Direct Testimony, page 8, lines 22 to 27.

¹⁰⁹ Richard Direct Testimony, page 9, lines 16 to 20.

¹¹⁰ Richard Direct Testimony, Exhibit SDR, page 2.

¹¹¹ Richard Direct Testimony, page 9, Chart 3.

¹¹² Richard Direct Testimony, page 9, line 24 to 25.

¹¹³ Richard Direct Testimony, page 7, Chart 3.

REDACTED

1 \$0.5 million in Property Tax related to the Mustang, ACI, and LNB investments.¹¹⁴

2 In total, OG&E proposes to recover an estimated \$15.4 million under the EGP rider
3 in 2015.¹¹⁵

4

5 **Q. Do you have any comments regarding this calculation in 2015?**

6 A. Yes. I have no concerns with the \$13.8 million CWIP return earned on the \$117.8
7 million investment outlay in 2015. My comments relate to the additional recovery
8 of Depreciation and Property Tax costs in 2015. Those costs, as well as the other
9 costs included in Chart 3 of Ms. Richard's testimony such as O&M Expense and
10 Regulatory Asset Amortization, should not be recovered through the EGP rider
11 until the asset to which the investment is related is in service. Doing so would
12 mean a divergence from pure CWIP recovery. In this instance, OG&E has
13 indicated that some of the environmental control system assets have already been
14 placed in service, and more are projected to be placed in service in 2015,¹¹⁶ so
15 some recovery of Depreciation and Property Tax costs may be appropriate in
16 2015. Nevertheless, the Commission should ensure that OG&E recovers only
17 CWIP on assets not yet in service and that any additional costs in the EGP rider,
18 such as Depreciation and Property Taxes, be recovered only once those assets
19 are placed into service. The same principles should be applied to all years in which
20 OG&E seeks rate recovery.

21

¹¹⁴ Exhibit CRR-19, OG&E response to Data Request AG 1-6_Att.

¹¹⁵ Richard Direct Testimony, page 7, Chart 3.

¹¹⁶ Exhibit CRR-20, OG&E response to Data Request OIEC 11-1.

REDACTED

1 **Q. Does OG&E claim that its rate recovery mechanism, especially the EGP rider,**
2 **provide any ratepayer protections?**

3 A. Yes. OG&E claims that there are three ratepayer protections in its EGP rider
4 proposal.¹¹⁷

5
6 **Q. Please describe the first ratepayer protection that OG&E claims is in the EGP**
7 **rider.**

8 A. OG&E states that the EGP rider provides “a smooth transition to full cost recovery
9 over a period of years, mitigating rate shock, while still fairly compensating
10 shareholders.”¹¹⁸ This “protection” is achieved, according to OG&E, by the use of
11 CWIP plus OG&E’s proposal to cap the annual increase in rates for each rate class
12 at 3.5 percent for the first five years of the EGP rider.¹¹⁹ OG&E states that the
13 EGP rider, as proposed, “will lead to a gradual increase of between 0.7 percent
14 and 3.3 percent a year” for a residential customer compared with an increase of
15 5.4 percent in 2019 with AFUDC regulatory treatment.¹²⁰

16
17 **Q. Do you agree that this is a significant ratepayer protection for OG&E**
18 **ratepayers?**

19 A. No. I do not dispute OG&E’s numbers on this point. However, I do not agree that
20 this is a significant ratepayer protection for two reasons. First, while CWIP can be
21 used to prevent rate shock, that benefit comes at a cost to ratepayers. Specifically,

¹¹⁷ Richard Direct Testimony, page 2, line 29 to page 3 line 31.

¹¹⁸ Richard Direct Testimony, page 2, lines 29 to 31.

¹¹⁹ Richard Direct Testimony, page 11, lines 5 to 7.

¹²⁰ Rowlett Direct Testimony, page 17, lines 5 to 11.

REDACTED

1 CWIP is a form of a zero-interest loan to the utility from its ratepayers to help
2 finance a project before it begins benefitting ratepayers.
3
4 Second, the five-year rate increase cap proposed by OG&E only provides short-
5 term comfort that rates will not increase by more than 3.5 percent annually during
6 the first five years of the EGP rider. It does not cap the total dollars ratepayers will
7 pay. Once the five-year period ends, OG&E can recover the entirety of its actual
8 costs related to the environmental compliance plan and Mustang modernization
9 plan. The proposed EGP rider states: "Any Oklahoma Jurisdiction EGP Revenue
10 Requirement in excess of the cap will be collected in a subsequent period;
11 however, this adjustment to the subsequent factor will not exceed the cap and will
12 be deferred to a future period."¹²¹ In other words, again, if the annual rate cap of
13 3.5 percent does limit the total dollar rate increases, for any of the five years, OG&E
14 customers will simply pay any overage in future years. The point is that the five-
15 year rate cap provides no protection to ratepayers against OG&E passing through
16 to them capital cost overruns, the cost of underperformance, or project delays.
17 Additionally, the Commission should note that the 3.5 percent rate cap for the first
18 five-year period applies only to the EGP rider, not to rate increases due to
19 additional costs recovered through the FAC. OG&E provides an estimate of the
20 overall rate impact of both the EGP rider and FAC customer impact during the five-

¹²¹Richard Direct Testimony, Exhibit SDR-2, page 3.

REDACTED

1 year EGP rider rate cap period,¹²² and estimates that total FAC increases will begin
2 in 2016 at \$37.1 million.¹²³

3

4 **Q. Please describe the second ratepayer protection that OG&E claims is in the**
5 **EGP rider.**

6 A. The second ratepayer protection, according to OG&E, is “enhancing regulatory
7 oversight with a true-up provision which ensures [OG&E] only recovers its actual
8 approved revenue requirement.”¹²⁴ OG&E commits to submit an annual true-up
9 of under or over collections of revenue.¹²⁵

10

11 **Q. Do you agree that the true-up provision provides significant ratepayer**
12 **protections?**

13 A. No. I do not dispute that true-up provisions provide an important, albeit basic,
14 method of accounting for revenues recovered. However, the true-up provision
15 does not address my longer-term concern that the EGP rider, once approved,
16 saddles OG&E ratepayers with the risk of cost overruns, underperformance, and
17 project delays. True-up provisions help prevent accounting errors; they do not
18 protect against cost overruns and poor performance. As previously noted, the
19 EGP rider explicitly states that OG&E can recover “all project expenditures” under
20 the rider, that the rider remains in effect with no set expiration date, and that

¹²² Richard Direct Testimony, page 12, Chart 5. Also, Exhibit CRR-17, OIEC 3-2_Att shows the customer impact through 2044 (although it assumes on budget performance).

¹²³ Richard Direct Testimony, page 5, Chart 2.

¹²⁴ Richard Direct Testimony, page 3, lines 1 to 2.

¹²⁵ Richard Direct Testimony, page 3, lines 7 to 9.

REDACTED

1 OG&E's estimated customer impact from the EGP rider is just that – an estimate
2 – that is non-binding. Nowhere in the EGP rider language proposed is OG&E held
3 to a firm cap on its capital investment or operating cost.
4

5 **Q. Please describe the third ratepayer protection that OG&E claims is in the**
6 **EGP rider.**

7 A. The third ratepayer protection, according to OG&E, is through “supplementary
8 reporting to track and audit the plan.”¹²⁶ OG&E “proposes providing the
9 Commission staff supplementary reports annually detailing the projects to be
10 included for recovery through the EGP rider for the next reporting period, the
11 estimated costs associated with those projects, a comparison of prior period actual
12 costs to previously supplied estimates, a brief description of the projects progress,
13 as well as other workpapers and documentation supporting the projects and the
14 costs.”¹²⁷ OG&E claims that this is all “meant to provide staff greater detail for
15 review and oversight” and “to review costs as they are incurred and included in the
16 EGP rider, instead of reviewing all the costs after the projects are completed.”¹²⁸
17

18 **Q. Do you agree that the annual reporting provision provides significant**
19 **ratepayer protections?**

20 A. No. While OG&E's commitment to provide regular reporting of its expenditures
21 and the progress of the projects is commendable, this commitment does not

¹²⁶ Richard Direct Testimony, page 3, lines 2 to 3.

¹²⁷ Richard Direct Testimony, page 3, lines 13 to 18.

¹²⁸ Richard Direct Testimony, page 3, lines 18 to 22.

REDACTED

1 provide any meaningful ratepayer protections. Again, as noted above, OG&E has
2 not provided a firm cost cap for its capital investments, nor has it provided any
3 language in the EGP rider that would limit the amount of investment it could
4 recover. This shifts risks of cost overruns, underperformance, and project delays
5 to ratepayers. The annual reporting requirement is not referenced in the proposed
6 EGP rider language, nor does OG&E claim at any point that the Commission can
7 deny recovery of costs once the EGP rider is accepted in the instant cause.

8
9 **Q. Do you have any other concerns with the annual reporting requirement that**
10 **OG&E claims is a ratepayer protection?**

11 A. Yes. Standing alone, these reports appear to be informational reports not subject
12 to Commission approval. Thus, while the annual reports may disclose OG&E's
13 actual and forecasted expenditures and construction progress on a year by year
14 basis, they seem to provide no additional ratepayer protection from paying for any
15 cost overruns or assuming the risk of poor performance or construction delays.

16
17 **Q. Did OG&E address this concern?**

18 A. No. When asked in a data request if "OGE's proposed cost tracking for the
19 environmental compliance plan and the Mustang modernization plan will
20 guarantee recovery of those costs and that such recovery is fundamentally
21 different than base rate recovery which does not guarantee cost recovery—but
22 rather allows a reasonable opportunity for cost recovery (including a reasonable
23 opportunity to earn a reasonable return)?", OGE stated: "No. The premise of the

REDACTED

1 question incorrectly characterizes the nature of uncertainty associated with the
2 utility's recovery of costs through authorized rates."¹²⁹ OG&E does not answer the
3 question so the issue of whether Commission approval implies a guarantee must
4 be open in OG&E's view.

5
6 **Q. Turning to the FAC, do you have any concerns with OG&E's proposal?**

7 A. Yes. My concern relates to the estimated increases in rates that will be treated as
8 a pass through. While I do not believe that OG&E should be required to take the
9 risk of changes in market prices for fuel and AQCS consumables, OG&E should
10 be held to its estimates for the operating performance of its plants. That is, OG&E
11 should be held to its estimates for the amount, per MWh, of fuel used to run its
12 generating assets and the amount of AQCS consumables needed to comply with
13 environmental regulations. Otherwise, OG&E will have license to pass all costs
14 through FAC with no protections for ratepayers. I include a recommendation
15 related to this concern below.

16
17 **VI. CONCLUSIONS AND RECOMMENDATIONS**

18 **A. ENVIRONMENTAL COMPLIANCE PLAN**

19 **Q. Having reviewed OG&E's evaluation of alternatives for its environmental**
20 **compliance plan, what is your conclusion?**

¹²⁹ Exhibit CRR-21, OG&E response to Data Request OER 1-12.

REDACTED

1 A. Having reviewed OG&E's evaluation of its five proposed compliance alternatives,
2 I conclude that OG&E's evaluation is incomplete.

3

4 **Q. Given this conclusion, what do you recommend to the Commission?**

5 A. I recommend that the Commission approve OG&E's choice of the *Scrub/Convert*
6 environmental compliance alternative, but do so *with conditions*. I recommend
7 approval because this alternative appropriately offers a diversified portfolio of
8 actions in the face of uncertainties. However, the precise mix of actions rely
9 heavily on OG&E's assumptions and analyses, which are incomplete. Conditions
10 are necessary to put the risk of incompleteness on OG&E rather than on the
11 Oklahoma ratepayer.

12

13 **Q. What conditions do you recommend?**

14 A. For the two retrofitted coal units at the Sooner facility, I recommend that approval
15 be subject to the condition that, if these units are shut down at any time prior to
16 2044, OG&E would not receive compensation for stranded investment. Related to
17 this is the condition that the recovery of the capital costs associated with the
18 Sooner facility be over the book lives associated with those same investments in
19 OG&E's analysis.¹³⁰ In addition, I recommend that OG&E be held to the capital
20 cost and operating performance that it assumed for the retrofitted Sooner plants.

21

¹³⁰ The book lives are presented in OG&E's response to Data Request OIEC 3-12, Attachment 71 (Exhibit CRR-2).

REDACTED

1 For the two units at Muskogee, I recommend that OG&E be held to the capital cost
2 and operating performance that it assumed for these converted plants. Operating
3 performance here includes, for its converted plants, heat rate, ramp rate, and cold
4 and hot start times. Further, these operating parameters would limit cost recovery
5 for the participation of the Muskogee units in the SPP market. For example, the
6 assumed heat rate curve for the converted Muskogee units would limit fuel cost
7 recovery.

8

9 **B. MUSTANG MODERNIZATION PLAN**

10 **Q. What is your conclusion about OG&E's Mustang modernization plan?**

11 A. Having reviewed the Mustang modernization plan, I find that OG&E's assessment
12 of that Plan is incomplete.

13

14 **Q. What do you recommend to the Commission?**

15 A. I recommend that the Mustang modernization plan be deferred until the successful
16 completion of a competitive procurement. Bids would be invited from both natural
17 gas-fired combustion turbines and combined cycle plants. Bids can be from any
18 site that is or could become a Network Resource; as in previous procurements,
19 SPP will be asked to judge whether such a designation would necessitate system
20 costs, which would be included in bid evaluation.

21

REDACTED

1 In addition, any bidder should be eligible to build at the Mustang site so that
2 Oklahoma ratepayers can enjoy the potential for lower costs that might result.
3 Finally, OG&E would be required to bid under the same rules as all other bidders.

4

5 As to the timing of Mustang unit retirements, the bids would determine the best
6 pace.

7

8 **Q. Do you have a recommendation regarding OG&E's proposed ratemaking**
9 **treatment?**

10 A. Yes. As explained above, the Commission should defer its rate recovery decision
11 at this time and consider recovery of OG&E's environmental compliance plan in
12 OG&E's next rate case. This will allow the Commission the opportunity to review
13 all of OG&E's expenses and revenues and determine the proper recovery for
14 OG&E as a whole at that time.

15

16 However, I have several recommendations regarding OG&E's rate recovery
17 proposal, whether addressed by the Commission in this proceeding or in the future
18 rate proceeding. I recommend that the OG&E rate proposal embed the cost caps
19 and performance requirements set here as conditions for approval of the
20 environmental compliance plan. I recommend that OG&E not be allowed to earn
21 any return on capital investment beyond the firm, fixed amount it specifies, nor can
22 OG&E earn CWIP returns on more than this amount or for periods beyond the
23 projected construction time if construction delays occur. I recommend that OG&E

REDACTED

1 not recover any depreciation, property tax, O&M expense, or regulatory asset
2 amortization costs through the EGP rider until the underlying assets to which those
3 costs are associated are in service.

4

5 Regarding increases in costs recovered through the FAC, I recommend that OG&E
6 be held to the same plant performance estimates discussed above, including fuel
7 and AQCS consumables amounts.

8

9 **Q. Do you have any additional recommendations?**

10 A. Yes. I recommend that the Commission require OG&E to submit a compliance
11 report establishing how the conditions here are implemented in rates.

REDACTED

ATTACHMENT ONE: THE COMMISSION'S EXPERIENCE WITH PSO'S PROPOSED ENVIRONMENTAL COMPLIANCE PLAN GIVES IT A USEFUL POINT OF COMPARISON AND HIGHLIGHTS MAJOR ISSUES TO ADDRESS

1 **Q. What is the purpose of this attachment?**

2 A. As already noted, the Commission has encountered the issues in this proceeding
3 previously in a proceeding concerning PSO's Environmental Compliance Plan –
4 Cause No. PUD 201200054. For several reasons the PSO proceeding in 2012
5 and 2013 gives the Commission a useful point of comparison for OG&E's proposal
6 and, thereby, gives it a heads up on many of the core issues for this proceeding.

7

8 First, the PSO proceeding was all about compliance with the same two regulations
9 that OG&E seeks to comply with in this proceeding: the RHR and the MATS.

10

11 Second, the technological alternatives for compliance considered by PSO and
12 OG&E were similar.

13

14 Third, the approach to evaluating the alternative for compliance was comparable:
15 estimate the present value of system-wide costs under each option and then show
16 the sensitivity of that cost estimate to changes in important assumptions such as
17 (a) the potential for new regulations in the future – including new regulations to
18 combat global climate change – and (b) the path of natural gas prices over the next
19 several decades.

20

REDACTED

1 Fourth, the Commission can see that for both PSO and OG&E the differences in
2 system cost impacts between compliance alternatives are often relatively small.
3 There is often a much larger potential impact on system costs from varying natural
4 gas prices and other risks. The race amongst alternatives is sometimes best seen
5 as a dead heat. Importantly, the tie breaker is an assessment of risks.

6
7 Fifth, the PSO proceeding shows the potential for including alternatives involving
8 existing natural gas-fired combined cycle plants by conducting a fair, open, and
9 transparent competitive procurement. PSO chose to do so on its own, while OG&E
10 chose not to.

11
12 Sixth and finally, there is more regulatory certainty in this OG&E proceeding than
13 there was for PSO. PSO came before the Commission with an EPA settlement
14 that was not finalized, and at a time prior to many major legal challenges to the
15 RHR and MATS having been decided. In comparison, OG&E has exhausted its
16 legal challenges to the RHR, and there have been two more years during which
17 these regulations have been upheld in court.

18
19 **Q. Are you suggesting the issues and solution must be the same for PSO and**
20 **OG&E?**

21 **A.** No. Differences in their systems might lead to different issues and solutions. Still,
22 the PSO proceeding helps define the possible issues and solutions.

23

REDACTED

1 **Q. Please give a concise overview of the facts in the PSO case.**

2 A. Allow me to provide a concise overview of the facts in the PSO proceeding with
3 the following points.

4

5 One, PSO settled with the U.S. EPA on compliance under the same two
6 environmental regulations that OG&E is attempting to comply with in the present
7 cause: RHR and MATS. The heart of the “EPA Settlement” was the agreement on
8 what to do with the two coal-fired units at PSO’s Northeastern power plant near
9 Oologah, Oklahoma; the two comparably sized units had a total of 930 MW of
10 capacity. PSO agreed to shut down one of the two units in 2016 and retrofit the
11 other unit with environmental controls before shutting it down in 2026.¹³¹

12

13 Two, to replace the power from the shut down unit, PSO conducted, at its own
14 initiative, a competitive procurement in which it chose a bid from one of Calpine’s
15 existing combined cycle plants in Oklahoma.¹³² This RFP took about five months
16 – it was issued April 13, 2012 and a contract was signed September 21, 2012.¹³³

17

18 Three, the other Northeastern unit was retrofitted with a package of controls to
19 address both the RHR and MATS. Those controls included dry-sorbent injection
20 system (DSI), activated carbon injection system (ACI), and a fabric filter baghouse

¹³¹ Roach Responsive Testimony in Cause No. PUD 201200054”, page 4, lines 13 to 17.

¹³² Roach Responsive Testimony in Cause No. PUD 201200054, page 3, lines 1 to 2 and page 27 lines 4 to 7.

¹³³ Roach Responsive Testimony in Cause No. PUD 201200054, page 55, footnote 77 and page 53 footnote 74.

REDACTED

1 (FF).¹³⁴ Essentially, the EPA Settlement allowed PSO to install DSI to control SO₂
2 emissions instead of installing the more expensive (and more effective) technology
3 called flue gas desulfurization (FGD) or “scrubbers.”¹³⁵ Although it was to be
4 retrofitted at considerable expense, under the settlement this second coal unit at
5 Northeastern would be retired just ten years later in 2026. As we understand it,
6 the logic of the settlement was that it would achieve the same total, cumulative
7 sulfur dioxide emissions as the installation of FGD on both Northeastern units and
8 their continued operation for 25 years.¹³⁶

9 Four, PSO evaluated alternatives to the EPA Settlement.¹³⁷ Central to the
10 evaluation was the estimation of the present value of system costs under each of
11 the alternatives. PSO defined the alternative compliance plans using colorful, but
12 instructive names. There were two “Coal is King” alternatives. In both of these
13 alternatives, both of the Northeastern coal-fired plants would be retrofitted with the
14 more expensive environmental controls – FGD, ACI, and FF. The only difference
15 between the two Coal is King alternatives was the length of time the retrofitted
16 coal-fired units were assumed to operate into the future. In Coal is King-25 Year,
17 the retrofitted units were assumed to operate for another 25 years. In the Coal is
18 King-15 Year plan, the units were assumed to operate for another 15 years – this

¹³⁴ Roach Responsive Testimony in Cause No. PUD 201200054, page 4, lines 14 to 16.

¹³⁵ Roach Responsive Testimony in Cause No. PUD 201200054, page 27, line 16 to page 28 line 2.

¹³⁶ Roach Responsive Testimony in Cause No. PUD 201200054, page 8, lines 9 to 12.

¹³⁷ Roach Responsive Testimony in Cause No. PUD 201200054, page 8, lines 19 to 20.

REDACTED

1 reflected the view that ever-tightened environmental regulation would lead to this
2 earlier shut down.¹³⁸

3

4 The two “Goldilocks” alternatives would shut down one of the coal units – replacing
5 it with a power purchase agreement (PPA) from a combined cycle plant. The other
6 coal unit would be retrofitted with FGD, ACI, and FF. Again, the key distinction
7 between the two Goldilocks alternatives was how long the retrofitted coal unit
8 would be assumed to operate into the future – 25 or 15 years.¹³⁹

9

10 The “Dash to Gas” scenario assumed that both coal plants were shut down. They
11 were replaced with natural gas-fired power – one unit by a PPA with a combined
12 cycle plant and the other by a combined cycle plant built by PSO.¹⁴⁰

13

14 **Q. What were the results of PSO’s evaluation?**

15 A. PSO estimated that the installation of FGD on either one or two units would be less
16 expensive than the EPA settlement on a net present value basis *if* – and the ‘if’ is
17 quite important – the coal-fired units retrofitted with FGD were assumed to operate
18 for 25 years.¹⁴¹ With the potential for significant additional environmental controls
19 on coal-fired power plants in the coming years, PSO did not believe the coal plants
20 would be allowed to operate for another 25 years and, instead, would be shut

¹³⁸ Roach Responsive Testimony in Cause No. PUD 201200054, page 9 lines 1 to 4.

¹³⁹ Roach Responsive Testimony in Cause No. PUD 201200054, page 9 lines 5 to 11.

¹⁴⁰ Roach Responsive Testimony in Cause No. PUD 201200054, page 9 lines 12 to 13.

¹⁴¹ Roach Responsive Testimony in Cause No. PUD 201200054, Table 1 on page 10.

REDACTED

1 down.¹⁴² Compared to a retrofit of the coal-fired unit that would last just 15 years,
2 the EPA settlement was estimated to offer the lowest reasonable, risk-adjusted
3 cost.¹⁴³

4
5 **Q. Please discuss some of PSO's specific quantitative findings?**

6 A. Table One shows PSO's quantitative results in terms of the difference in the
7 present value of system costs using PSO's base case commodity price scenario.

**Attachment Table One
Cumulative Present Worth of Options in 2011
Compared to the EPA Settlement Option,
Under PSO Base Case Commodity Price Scenario**

	Coal is King- 25 Year	Coal is King- 15 Year	Goldilocks- 25 Year	Goldilocks- 15 Year	Dash to Gas
Difference from EPA, %	(-1.9%)	1.4%	(-0.8%)	0.8%	1.2%
Difference from EPA, \$ millions	(-\$278)	\$203	(-\$117)	\$116	\$170

Source: Roach Responsive Testimony in Cause No. PUD 201200054, Table 1 on page 10.

8 **Q. What is most important to see in Table One?**

9 A. Three important results can be seen in Table One.

10

11 First, PSO's proposed EPA Settlement was not always the lowest cost

12 alternative. The Coal is King-25 Year plan is estimated to be 1.9 percent less

¹⁴² Direct Testimony of Scott C. Weaver on Behalf of Public Service Company of Oklahoma, Oklahoma Corporation Commission Cause No. PUD 201200054, filed September 26, 2012 ("Weaver Direct Testimony in Cause No. PUD 201200054"), page 45 lines 14 to 23.

¹⁴³ Roach Responsive Testimony in Cause No. PUD 201200054, Table 1 on page 10.

REDACTED

1 costly. So, too, the Goldilocks-25 Year plan was estimated to be 0.8 percent less
2 costly.

3

4 Second, if the shorter 15-year alternatives were considered more realistic than
5 the 25-year plans, then the EPA Settlement was the lowest cost plan. Coal is
6 King-15 Year was 1.4 percent more costly and Goldilocks-15 Year was 0.8
7 percent more costly than the EPA Settlement.

8

9 Third, the Dash to Gas alternative was estimated to be 1.2 percent more costly
10 than the EPA Settlement.

11

12 **Q. Did PSO evaluate the compliance alternatives under assumptions other**
13 **than those in the Base Case?**

14 A. Yes. PSO also evaluated the compliance alternatives under high and low
15 commodity price sensitivities, the high commodity price scenario at my
16 request.¹⁴⁴ This was an effort to show the uncertainties surrounding all these
17 forecasts. As expected, in the low commodity price sensitivity – notably, a lower
18 level of natural gas prices – the EPA Settlement looked comparatively less costly
19 than the Coal is King and Goldilocks options because it relies on natural gas
20 more heavily.¹⁴⁵ With the high commodity price sensitivity, the EPA Settlement

¹⁴⁴ Roach Responsive Testimony in Cause No. PUD 201200054, page 37, lines 6 to 10.

¹⁴⁵ Roach Responsive Testimony in Cause No. PUD 201200054, page 45, lines 2 to 5.

REDACTED

1 looked relatively more expensive than those alternatives that relied more heavily
2 on coal.¹⁴⁶

3

4 **Q. Was the impact of a carbon price evaluated?**

5 A. Yes. All PSO sensitivities, including the base case, assumed that there would be
6 a price on carbon of about \$15 for every ton of greenhouse gas emissions,
7 beginning in 2022. The one exception was the “Early Carbon” scenario that
8 assumed a carbon price would begin in 2017.¹⁴⁷

9

10 **Q. How did you summarize the impact of all these alternative results?**

11 A. In my Testimony in the PSO proceeding, I highlighted the impact of this
12 uncertainty by showing how risk assessment could dictate the Commission’s
13 choice among the plans.¹⁴⁸

14 Q. Do these competing risks make it a close call for you?

15

16 A. Yes. It is a close call between (a) approving cost recovery for
17 the EPA Settlement option and (b) rejecting it in favor of the
18 installation of FGD/ACI/FF on both units (as in Coal is King-
19 25 Year). It is all about difficult assessments of relative risks.

20

21 On the one hand, it could be argued, as I have, that the risk
22 of early shutdown of FGD/ACI/FF retrofitted plants is
23 substantial and that the risk of high natural gas prices is low
24 due to the shale gas revolution. With this assessment, the
25 EPA Settlement option is estimated to cost ratepayers about
26 2.1% less than FGD/ACI/FF retrofits.

27

28 On the other hand, it could be argued that the risk of early
29 shutdown of FGD/ACI/FF-retrofitted plants is low, and the risk

¹⁴⁶ Roach Responsive Testimony in Cause No. PUD 201200054, page 45, lines 10 to 13.

¹⁴⁷ Scott C. Weaver Direct Testimony, Cause No. PUD 201200054, page 39, line 6 to page 41, line 2.

¹⁴⁸ Roach Responsive Testimony in Cause No. PUD 201200054, page 13, line 9 to page 14, line 2 (internal cites removed).

REDACTED

1 of high natural gas prices is substantial. With this assessment
2 of risks, the EPA Settlement option is estimated to cost
3 ratepayers about 3.7% more than the FGD/ACI/FF retrofits.
4

5 **Q. What was the outcome of the PSO proceeding?**

6 A. The Settlement that PSO agreed to with EPA was not finalized at the time of the
7 PSO proceeding. Delays in reaching a final state implementation plan (SIP) led to
8 the cause being stayed in March 2013. Subsequent to that stay, PSO indicated
9 that it had a need for additional capacity due to increased load forecast. As a result
10 of all the uncertainty, the cause was dismissed August 13, 2013.¹⁴⁹ It is my
11 understanding that PSO will later come back to the Commission to request rate
12 recovery.

¹⁴⁹ Cause No. PUD 201200054, Order No. 614773, August 13, 2013

REDACTED

EXHIBIT CRR-1
LIST OF TESTIMONY AND PUBLICATIONS BY
CRAIG R. ROACH, Ph.D.

REDACTED

**LIST OF TESTIMONY AND OTHER PUBLICATIONS
FOR CRAIG R. ROACH, Ph.D.**

TESTIMONY

Rebuttal Evidence concerning the review of the AUC's previous decision on transmission loss methodology. Alberta Utilities Commission Proceeding ID 2581. [September 2013]. Filed as an Expert Witness on behalf of the Generator Group.

Surrebuttal Testimony concerning our evaluation of the Fisherman's Atlantic City Wind Farm application to sell offshore renewable energy certificates. State of New Jersey Board of Public Utilities Docket No. E011050314V. [May 2013]. On behalf of the Board of Public Utilities Staff.

Direct Testimony concerning the allegation that the New Jersey Board of Public Utilities' Long-Term Capacity Agreement Pilot Program violates the Supremacy Clause and the Commerce Clause of the United States Constitution. U.S. District Court (District of New Jersey) Civil Action No. 11-745 PSG. [May 2013]. On behalf of the State of New Jersey, Department of Law and Public Safety, Division of Law.

Affidavit concerning FirstEnergy's Complaint related to underfunding of FTRs in PJM's Markets. Federal Energy Regulatory Commission Docket No. EL13-47-000. [March 2013]. On behalf of the Maryland Public Service Commission.

Direct Testimony concerning the allegation that the Maryland Public Service Commission's competitive procurement for long-term capacity violates the Supremacy Clause and the Commerce Clause of the United States Constitution. U.S. District Court (Maryland, Northern Division) Civil Action No. 12-1286 MJG. [March 2013]. On behalf of the Maryland Public Service Commission.

Responsive, Rebuttal and Surrebuttal Testimony concerning the application of the Public Service Company of Oklahoma for commission authorization of a plan and cost recovery for actions by PSO to be in compliance with certain environmental rules promulgated by the United States Environmental Protection Agency, Cause No. PUD 201200054. [January, February, and March 2013, respectively]. Filed on behalf of the Oklahoma Corporation Commission Staff and the Office of the Oklahoma Attorney General.

Responsive Testimony concerning whether Public Service Company of Oklahoma should be granted Contract Earnings on costs associated with a power purchase agreement, before the Corporation Commission of Oklahoma, Cause No. PUD 201200079. [September 2012]. Filed on behalf of the Oklahoma Corporation Commission Staff and the Office of the Oklahoma Attorney General.

REDACTED

Direct and Rebuttal Evidence concerning the Alberta Electric System Operator's approach to allocating transmission import capability, Alberta Utilities Commission, Proceeding 1633. [May and July 2012]. Filed on behalf of TransCanada Energy Ltd.

Summary at Hearing regarding whether new generating capacity is needed to meet long-term demand for Standard Offer Service, the Public Service Commission of Maryland, Case No. 9214. [January 2012]. Filed as Consultants to the Public Service Commission of Maryland.

Direct Testimony providing a recommendation to the Maryland Public Service Commission on whether to accept the results of the Maryland Utilities' 2012 Request for Proposals (RFP) for Standard Offer Service, the Public Service Commission of Maryland, Case Nos. 9056 and 9064. [October 2011, January 2012]. Filed on behalf of the Staff of the Public Service Commission of Maryland.

Opening Statement concerning Milner Power Inc.'s Transmission Loss Factor Rule and Loss Factor Methodology Complaint, Alberta Utilities Commission, Application No. 1606494, [October 2011]. Filed by TransCanada Energy Ltd.

Surrebuttal Testimony concerning Entergy Arkansas' proposal to become a member of Midwest ISO. Presented to the Arkansas Public Service Commission Case No. 10-11-U, [August 2011]. Filed as Expert Witness on behalf of Southwest Power Pool, Inc.

Written Evidence concerning Milner Power Inc.'s Transmission Loss Factor Rule and Loss Factor Methodology Complaint, Alberta Utilities Commission, Application No. 1606494, [July 2011]. Filed as Expert Witness on behalf of TransCanada Energy Ltd., TransAlta Corporation, and Capital Power Corporation.

Supplemental Initial Testimony concerning Entergy Arkansas' proposal to become a member of Midwest ISO. Presented to the Arkansas Public Service Commission Case No. 10-11-U, [July 2011]. Filed as Expert Witness on behalf of Southwest Power Pool, Inc.

Reply comments concerning the 2011 Procurement Process, before the Illinois Commerce Commission [July 2011]. Filed as the Procurement Monitor.

Affidavit concerning the proposed merger of Duke Energy Corporation and Progress Energy, Inc., Federal Energy Regulatory Commission Docket No. EC11-60-000 [June 2011]. [Client settled before filing.]

Direct Testimony providing a recommendation to the Maryland Public Service Commission on whether to accept the results of the Maryland Utilities' 2011 Request for Proposals (RFP) for Standard Offer Service, the Public Service Commission of Maryland, Case Nos. 9056 and 9064. [October 2010, January 2011, April 2011, June 2011]. Filed on behalf of the Staff of the Public Service Commission of Maryland.

REDACTED

Expert Report concerning HydroQuebec's calculations of ATC and its transmission planning process, Régie de l'énergie, No. R-3669-2008, Phase 2, [September 2010]. Filed on behalf of Énergie Brookfield Marketing, Inc.

Expert Report concerning rollover rights and curtailment under HydroQuebec's OATT, Régie de l'énergie, Nos. P130-001 and P130-003 [July 2010] Filed on behalf of Énergie Brookfield Marketing, Inc.

Reply comments concerning the 2010 Procurement Process, before the Illinois Commerce Commission [July 2010]. Filed as the Procurement Monitor.

Direct and Supplemental Testimony concerning the application of Oklahoma Gas and Electric Company to construct the Crossroads wind farm, Cause No. PUD 201000037 [June and July 2010]. Filed on behalf of The Oklahoma Corporation Commission.

Report on the Open Season for Zephyr Power Transmission LLC, Federal Energy Regulatory Commission, Docket No. ER09-433-000 [May 2010]. Filed as the Independent Evaluator for Zephyr Power Transmission, LLC.

Phase Two Report of the Independent Evaluator concerning proposed alternatives to Mississippi Power Company's IGCC facility, Docket No. 2009-UA-014 [January 2010]. Filed as Consultant to the Mississippi Public Service Commissioners.

Phase Two Direct Testimony concerning Mississippi Power Company's proposed IGCC facility, Docket No. 2009-UA-014 [December 2009]. Filed as Consultant to the Mississippi Public Service Commissioners.

Phase One Direct Testimony concerning Mississippi Power Company's petition for acquisition, construction, and operation of an Integrated Gasification Combined Cycle (IGCC) facility, Docket No. 2009-UA-014 [July 2009]. Filed as Consultant to the Mississippi Public Service Commissioners.

Responsive Testimony concerning the cost recovery and approval of a power purchase agreement between PSO and Exelon Generation, LLC, Oklahoma Corporation Commission Cause No. PUD 200900099 [July 2009]. Filed as the Oklahoma Commission's Independent Evaluator.

Reply comments concerning the 2009 Procurement Process, before the Illinois Commerce Commission [June 2009]. Filed as the Procurement Monitor.

Direct and Rebuttal Testimony concerning a service agreement between TransCanada Energy Ltd. and British Columbia Transmission Corporation for long term firm point-to-point transmission service. British Columbia Utilities Commission Project No. 3698539 [March and April 2009]. For TransCanada Energy Ltd.

REDACTED

Report responding to the Commission's inquiries on emissions costs, construction costs, and fuel costs, Minnesota Public Utility Commission Docket No. CN-05-619 [October 2008]. For the Minnesota Commission.

Testimony and Rebuttal Testimony concerning the design of the 2008 RFP, Oklahoma Corporation Commission Cause No. PUD 200700418 [June and August 2008]. Filed as the Oklahoma Commission's Independent Evaluator.

Comments concerning PacifiCorp's proposed acquisition of the Chehalis power plant, Oregon Public Utility Commission Docket No. UM 1374 [June 2008]. Filed as the Oregon Independent Evaluator.

Reply comments concerning the 2008 Procurement Process, before the Illinois Commerce Commission [May 2008]. Filed as the Procurement Monitor.

Comments concerning the 2008 Procurement Process, before the Illinois Commerce Commission [May 2008]. Filed as the Procurement Monitor.

Direct Testimony concerning the proposed acquisition of TXU by private equity investors, Public Utility Commission of Texas Docket No. 34077 [September 2007]. For the Texas Commission.

Comments concerning PacifiCorp's proposal to amend and delay its 2012 RFP, Oregon Public Utility Commission Docket No. UM 1208. [November 2007]. Filed as the Oregon Independent Evaluator.

Affidavit concerning allegations of above-market prices and price manipulation in the 2006 Illinois Auction, Federal Energy Regulatory Commission Docket No. EL07-47-000. [June 2007]. Filed as the Auction Monitor.

Support for settlement of an electric transmission rate case, Federal Energy Regulatory Commission Docket No. ER06-186-000. [March and April 2006]. For the City of Vernon.

Testimony concerning market power mitigation measures for the Southwest Power Pool energy imbalance services market, Federal Energy Regulatory Commission Docket No. ER06-451-000. [January 2006]. Filed as the Southwest Power Pool's Independent Market Monitor.

Comments on the Maryland procurement process for Standard Offer Service, Maryland Senate Special Commission on Electric Utility Deregulation Implementation. [August 2005]. Appearing as the Technical Consultant for the Maryland Public Service Commission.

Direct and Supplemental Testimony concerning market power mitigation measures for the Southwest Power Pool energy imbalance services market, Federal Energy Regulatory

REDACTED

Commission Docket No. ER05-1118-000. [June and August 2005]. Filed as the Southwest Power Pool's Independent Market Monitor.

Comments on the open access status of a transmission line, Federal Energy Regulatory Commission Docket No. ER05-1072-000. [June 2005]. Filed as the Southwest Power Pool's Independent Market Monitor.

Direct Testimony regarding the benefit of continuing PUCT Capacity Auctions in Texas, Public Utility Commission of Texas, Docket No. 30882. [May 2005]. For Reliant Energy, Inc.

Expert Report regarding the basis for and quantification of damages, 249th Judicial District Court (Texas) Cause No. C-2002-00267. [March 2005]. For Ponderosa Pine Energy, L.L.C.

Panelist on transmission market power and barriers to entry, Federal Energy Regulatory Commission Technical Conference Docket No. RM04-7-000, Washington, DC. [December 2004].

Expert Report concerning damage estimates regarding power sales contract, American Arbitration Association Case No. 71 198 00323 01. [October 2004]. For Ponderosa Pine Energy Partners, LTD.

Panelist on solicitation processes for public utilities, Federal Energy Regulatory Commission Technical Conference Docket No. PL04-6-000, Washington, DC. [June 2004].

Affidavit and Supplemental Affidavit concerning the competitive effects of the proposed acquisition of Illinois Power by Ameren Corp., Federal Energy Regulatory Commission Docket No. EC04-81-000, Washington, DC. [May and June 2004]. For Aquila Merchant Services, Inc.

Direct Testimony on FirstEnergy's proposed Rate Stabilization Plan, Public Utilities Commission of Ohio Case No. 03-2144 EL-ATA, EL-AAM, EL-UNC. [February 2004]. For Reliant Resources, Inc. and Constellation Power Source.

Panelist on market power mitigation and measurement, Federal Energy Regulatory Commission Technical Conference on Supply Margin Assessment Screen and Alternatives Docket No. PL02-8-000, Washington, DC. [January 2004].

Direct and Answering Testimony concerning approval of affiliate power purchases by Entergy under the *Edgar* standard using a competitive solicitation test. Federal Energy Regulatory Commission Docket No. ER03-583-000. [November 2003 and April 2004]. For Calpine Corporation.

Direct and Answering Testimony and Cross-Answering Testimony concerning approval of an affiliate acquisition by AmerenUE under the *Edgar* standard using a competitive solicitation and benchmark data. Federal Energy Regulatory Commission Docket No.

REDACTED

EC03-53-000. [August and September 2003]. For the Electric Power Supply Association.

Affidavit concerning the application of the *Mobile-Sierra* doctrine to a Standard Offer Wholesale Sales Agreement for a supplier in bankruptcy. United States District Court (District of Columbia) Case No. 03-1189. [July 2003]. For NRG Power Marketing Inc.

Direct Testimony concerning Entergy's proposed Agreement in Principle including certain affiliate power sales, New Orleans City Council Docket Nos. UD-01-04 and UD-03-01. [April 2003] For Reverend C.S. Gordon, Jr., et al.

Expert Report concerning correct interpretation of power sales contract standards, American Arbitration Association Case No. 71 198 00323 01. [April 2003] For Tenaska IV Texas Partners, LTD.

Expert Report concerning the correct discount rate to be used in determining an award, American Arbitration Association Case No. 00 199 00199 02. [March 2003]. For TM Delmarva Power L.L.C.

Affidavit concerning market-based rate authority using the Supply Margin Assessment (SMA), Federal Energy Regulatory Commission Docket No. ER03-618-000. [March 2003]. For Reliant Energy Choctaw, LLC.

Expert Report concerning opportunities for reverse tolling transactions with Entergy, utility dispatch rules, and antitrust damages, Louisiana State Court Suit No. 467,116; Div. "N". [January 2003]. For Energy Transfer Group.

Affidavit concerning market-based rate authority using the Supply Margin Assessment (SMA), Federal Energy Regulatory Commission Docket No. ER03-382-000. [January 2003]. For Reliant Energy Solutions, LLC.

Direct and Rebuttal Testimony concerning Track B issues including types of competitive solicitation, products to be procured, and affiliate codes of conduct, Arizona Corporation Commission Docket No. E-00000A-02-0051, et al. [November 2002]. For Panda Gila River, L.P.

Panelist concerning the Resource Adequacy Requirement within the Standard Market Design, Federal Energy Regulatory Commission Technical Conference Docket No. RM01-12-000, Washington, DC. [November 2002].

Affidavit concerning market-based rate authority using the Supply Margin Assessment (SMA), Federal Energy Regulatory Commission Docket No. ER03-81-000. [October 2002]. For Reliant Energy Solutions West, LLC.

REDACTED

Affidavit concerning the method for determining natural gas prices for purposes of calculating refunds in California, Federal Energy Regulatory Commission Docket Nos. EL00-95-045, et al. [October 2002]. For Reliant Energy Power Generation, Inc.

Direct and Surrebuttal Testimony concerning affiliate asset transaction and competitive procurement, Wisconsin Public Service Commission Docket No. 05-CE-117. [August and September 2002]. For Midwest Independent Power Suppliers.

Direct and Responsive Testimony concerning affiliate asset transfer and competitive procurement, Indiana Utility Regulatory Commission Cause No. 42145. [July and October 2002]. For Midwest Independent Power Suppliers.

Direct and Rebuttal Testimony concerning Track A issues including asset transfer, market power, and codes of conduct, Arizona Corporation Commission Docket No. E-00000A-02-0051, et al. [May and June 2002]. For Panda Gila River, L.P.

Affidavit concerning the triennial update for market-based rate authority using the Supply Margin Assessment (SMA), Federal Energy Regulatory Commission Docket No. ER01-3103-002. [June 2002]. For Reliant Resources, Inc.

Affidavit concerning market-based rate authority using the Supply Margin Assessment (SMA), Federal Energy Regulatory Commission Docket No. ER02-1762-000. [May 2002]. For Reliant Energy Solutions East, LLC.

Direct Testimony concerning Arizona Public Service Company's request for approval of variance and affiliate power purchase agreement, Arizona Corporation Commission Docket No. E-00000A-02-0051, et al. [March 2002]. For Panda Gila River, L.P.

Direct Evidence concerning a proposal for transmission congestion management and expansion cost allocation, Alberta Energy and Utilities Board Application No. 1248859. [March 2002]. For TransCanada Energy Ltd.

Direct Evidence concerning competitive procurement and pricing for transmission must-run and other ancillary services, Alberta Energy and Utilities Board Application No. 1244140. [February 2002]. For Ancillary Services Group.

Comments concerning market power mitigation by RTOs, Federal Energy Regulatory Commission Technical Conference on Standard Electricity Market Design Docket No. RM01-12-000, Washington, DC. [February 2002].

Direct Testimony concerning prices and other terms and conditions for imbalance energy from Entergy, Federal Energy Regulatory Commission Docket EL02-46-000. [January 2002]. For Generator Coalition.

REDACTED

Direct Testimony concerning energy market conditions and energy availability in New Orleans, City Council of New Orleans Docket No. UD-00-2. [January 2002]. For Thomas Lowenburg, et al.

Initial and Reply Comments concerning the development of market-based mechanisms to evaluate proposals to construct or acquire generating capacity, Louisiana Public Service Commission Docket No. R-26,172. [December 2001 and January 2002]. For Sempra Energy Resources.

Expert Witness concerning abrogation of power sales agreement by Entergy, State of Alabama Circuit Court for Jefferson County, Civil Action Number CV9925070. [2001]. For Southern Company Services.

Direct Testimony and Supplemental Direct concerning the competitive effects of the proposed merger of Orion Power Holdings, Inc. and Reliant Resources Inc., Federal Energy Regulatory Commission Docket No. EC02-11-000. [October 2001 and January 2002]. For Applicants.

Comments and Request For Intervention concerning a proposed refund condition for market-based rates and methods of measuring market power, Federal Energy Regulatory Commission Docket No. EL01-118-000. [December 2001]. For Boston Pacific Company, Inc.

Comments concerning the role of market monitoring by RTOs, Federal Energy Regulatory Commission Conference on Electricity Market Design and Structure Docket No. RM01-12-000. [October 2001].

Affidavit concerning updated market power analysis in support of Carr Street Generating Station, L.P.'s market-based rate application, Federal Energy Regulatory Commission Docket No. ER98-4095-001. [October 2001]. For Orion Power Holdings, Inc.

Expert Report concerning calculation of damages due to a breach of contract, United States District Court (Eastern Texas) Case No. 1:00CV-283. [August 2001]. For EPCO Carbon Dioxide Products, Inc.

Direct Testimony concerning prudence of Wisconsin Electric Power Company's Power The Future-2 proposal, Public Service Commission of Wisconsin Docket No. 6630-DR-104. [June 2001]. For Midwest Independent Power Suppliers Coordination Group.

Direct Evidence Concerning Hydro Quebec's transmission rate application, Régie de L'Énergie Case R-3401-98. [February 2001]. For Ontario Power Generation, Inc.

Presentation of guiding principles for monitoring market power in markets run by the California ISO, Federal Energy Regulatory Commission Technical Conference Docket Nos. EL00-95-000, et al. [January 2001]. For the Electric Power Supply Association.

REDACTED

Affidavit concerning breach of contract by a utility and the resulting damages through the imposition of a cap on a rate discount known as the LEE Credit, Louisiana Public Service Commission Docket No. U-22801. [August 2000]. For Star Enterprise.

Direct, Supplemental Direct, Surrebuttal, and Rebuttal Testimony concerning the prudence of passing through the fuel adjustment clause certain electricity purchase costs and the costs of some utility-owned generation, New Orleans City Council Docket No. UD-99-2. [April and December 2000; March and August 2001]. For Reverend C.S. Gordon, Jr., et al.

Direct and Rebuttal Testimony concerning the pricing of Reliability Must-Run (RMR) Service to the California ISO, Federal Energy Regulatory Commission Docket Nos. ER98-496-006 and ER98-2160-004. [December 1999 and March 2000]. For Duke Energy Power Services.

Direct, Rebuttal, and Rebuttal to Staff Testimony concerning the prudence of electricity purchase costs passed through the fuel adjustment clause and the underlying, inter-company procurement practices and methods of economic dispatch, Louisiana Public Service Commission Docket No. U-23356. [July and November 1999; July 2000]. For Linda Delaney, et al.

Affidavit concerning the competitive effects of the proposed merger of Sempra Energy and KN Energy, Inc., Federal Energy Regulatory Commission Docket No. EC99-48-000. [May 1999]. For Questar Pipeline Company.

Direct and Oral Rebuttal Testimony concerning the competitive effects of the proposed merger of AEP and CSW, Federal Energy Regulatory Commission Docket Nos. EC98-40-000, ER98-2770-000, and ER98-2786-000. [April 1999]. For The Dayton Power and Light Company.

Direct, Supplemental, and Rebuttal Testimony concerning a rate proposal for the Associated Branch Pilots of the Port of New Orleans, Louisiana Public Service Commission. [October 1998]. For the Associated Branch Pilots.

Direct and Rebuttal Testimony concerning claims for damages by Public Service of Colorado based on alleged improper billings under a power purchase agreement with Tri-State, American Arbitration Association No. 77 Y 181 00230 97. [September and October 1998]. For Tri-State Generation and Transmission Association, Inc.

Testimony concerning a public records request, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Suit No. 449,691 Div. "A". [August 1998]. For CII Carbon, L.L.C.

Direct, Cross-Answering, and Surrebuttal Testimony concerning standby rates for self-generators, Louisiana Public Service Commission Docket No. U-20925-SC. [June, July, and August 1998]. For CII Carbon, L.L.C.

REDACTED

Direct and Surrebuttal Testimony concerning reliability, market power, functional unbundling, divestiture, default supplier, balancing and other restructuring issues, New Jersey Board of Public Utilities Docket No. EX94120585Y, et al. [March and April 1998]. For Mid-Atlantic Power Supply Association.

Declaration concerning antitrust issues made by Florida Power in a motion for summary judgment, United States District Court (Miami, Florida) Case No. 96-594-CIV-LENARD. [February 1998]. For Metropolitan Dade County and Montenay Power.

Comments concerning market power, market structure, reliability, and related topics in restructuring, Arkansas Public Service Commission Docket Nos. 97-451-U, 97-452-U, and 97-453-U. [February 1998]. For Arkansas Electric Energy Consumers.

Direct, Rebuttal, and Surrebuttal Testimony concerning a methodology for determining avoided cost prices, Louisiana Public Service Commission Docket No. U-22739. [November and December 1997; January 1998]. For CII Carbon, L.L.C.

Direct Testimony concerning Virginia Power's proposals for stranded cost recovery, Virginia State Corporation Commission Case No. PUE 960296. [December 1997]. For Virginia Independent Power Producers, Inc.

Rebuttal Testimony concerning rules for affiliate transactions in the proposed merger of Pacific Enterprises and Enova Corporation, California Public Utilities Commission No. A.96-10-038. [August 1997]. For Kern River Gas Transmission Company.

Direct Testimony concerning the proposed merger of Pacific Enterprises and Enova Corporation, California Public Utilities Commission No. A.96-10-038. [August 1997]. For Kern River Gas Transmission Company.

Rebuttal Testimony concerning the calculation of damages for the Abrogation of Tenaska's power purchase agreement by BPA, American Arbitration Association No. 77-198-0224-95. [July 1997]. For Tenaska, Inc.

Testimony concerning Ex-Im Bank and OPIC, before the Subcommittee on Tax, Finance, and Exports, Committee on Small Business, U.S. House of Representatives. [May 1997].

Testimony concerning the abrogation of Tenaska's power purchase agreement by BPA, American Arbitration Association No. 77-198-0224-95. [February 1997]. For Tenaska, Inc.

Direct Testimony concerning rolled-in rates on Transco, Federal Energy Regulatory Commission Docket Nos. RP95-197-000 and RP95-197-001 (Phase II). [January 1996]. For KCS Energy Marketing, Inc.

REDACTED

Direct Testimony concerning estimates of avoided costs by Louisiana Power & Light, Louisiana Public Service Commission Docket No. U-21384. [October 1995]. For Calciner Industries, Inc.

Surrebuttal Testimony concerning estimates of avoided costs by Empire District Electric Company, Missouri Public Service Commission Case No. EC-95-28. [June 1995]. For Ahlstrom Development Corporation.

Affidavit concerning Duke's market power study, Federal Energy Regulatory Commission Docket No. ER95-760-000. [April 1995]. For North Carolina Municipal Power Agency Number 1 and Piedmont Municipal Power Agency.

Direct Testimony concerning estimates of avoided costs by Empire District Electric Company, Missouri Public Service Commission Case No. EC-95-28. [January 1995]. For Ahlstrom Development Corporation.

Direct Testimony concerning a proposal for rolled-in rates by Pacific Gas Transmission, Federal Energy Regulatory Commission Docket No. RP94-149-000. [November 1994]. For Alberta Department of Energy.

Direct Testimony concerning proposal for market-based rates under Rate-K, Michigan Public Service Commission Case No. U-10625. [October 1994]. For Michigan Cogeneration Coalition.

Preliminary Written Comments concerning the need for and form of a request for proposals (RFP) by Carolina Power & Light, South Carolina Public Service Commission Docket No. 94-469-E. [August 1994]. For Carolina Competitive Energy Producers.

Initial and Reply Comments concerning guidelines for evaluation of unsolicited private power proposals, North Carolina Utilities Commission Docket No. E-100, Sub 64. [September and October 1993]. For Carolina Competitive Energy Producers.

Direct Testimony concerning Section 712 issues, Florida Public Service Commission Docket No. 921288-EU. [September 1993]. For Florida Competitive Energy Producer's Association.

Oral Testimony concerning Section 712 issues, Maryland Public Service Commission Case No. 8568. [August 1993]. For Mid-Atlantic Independent Power Producers.

Direct Testimony concerning Section 712 issues, Georgia Public Service Commission Docket No. 4384-U. [July 1993]. For Electric Generation Association.

Direct Testimony concerning the proposed merger of Entergy and Gulf States, Federal Energy Regulatory Commission Dockets Nos. EC92-21-000 and ER92-806-000. [March 1993]. For Arkansas Electric Energy Consumers.

REDACTED

Direct Testimony concerning New York curtailment proposals, New York Public Service Commission Case Nos. 92-E-0814 and 88-E-081. [February 1993]. For J. Makowski Associates, Inc.

Direct Testimony concerning Georgia Power Company's Integrated Resource Plan, Georgia Public Service Commission Dockets No. 4131-U and 4134-U. [June 1992]. For Mission Energy Company.

Direct and Rebuttal Testimony concerning Baltimore Gas and Electric's CPCN filing and Cogen Technologies' proposed QF, Maryland Public Service Commission Case No. 8241-Phase II. [August and September 1991]. For Mission Energy Company.

Direct Testimony commenting on Jersey Central Power & Light Company's request for proposals dated August 31, 1990, Docket No. 8010-678B. [December 1990]. For State of New Jersey Department of the Public Advocate [Co-sponsored].

Direct and Rebuttal Testimony concerning the sale/leaseback and restated agreement transaction for Springerville and San Juan power, Federal Energy Regulatory Commission Docket Nos. EL89-17-001 and EL89-18-001. [May and June 1990]. For Century Power Corporation.

Direct and Rebuttal Testimony concerning the proposed merger of Southern California Edison and San Diego Gas and Electric, Federal Energy Regulatory Commission Docket No. EC89-5-000. [November 1989 and January 1990]. For Century Power Corporation.

ARTICLES & SPEECHES

"Overview of the 2014 Annual Looking Forward Report: Strategic Issues Facing the Electricity Business." Presented to the SPP Board of Directors and Members Committee (April 29, 2014).

"Strategic Issues Facing the Electricity Business." Presented as part of a "Lunch and Learn" at the University of Chicago Booth School of Business (April 23, 2014).

Discussion of the recent federal preemption rulings in U.S. District Courts in Maryland and New Jersey. Presented as part of the Renewable Energy Webinar and Teleconference Series sponsored by ACORE and the ABA (March 19, 2014).

"Partnership, Not Preemption" (Coauthored) Public Utilities Fortnightly (December 2013).

"Brown Bag Presentation on Market Monitoring, Mitigation, and Competition." Presented to The Office of Energy Policy and Innovation at the Federal Energy Regulatory Commission (May 22, 2013).

REDACTED

“Overview of the 2013 Annual Looking Forward Report.” Presented to the SPP Board of Directors and Members Committee (April 30, 2013).

“Overview of the Annual Looking Forward Report.” Presented to the SPP Board of Directors and Members Committee (April 24, 2012).

“Using Competition to Benefit Consumers: An Implicit State-Federal Partnership.” Presented at Electricity Markets 101: An Overview of Electricity Market Structures, a Congressional briefing hosted by the Business Council for Sustainable Energy, the COMPETE Coalition, and the Electric Power Supply Association (October 5, 2011).

“America’s Electricity Future: What Drives the Choice Among Technologies?” Presented at the Energy Project Series hosted by Haynes & Boone, LLP (September 22, 2011).

“A Basic Electricity Primer.” Presented at the Natural Gas/Renewable Energy Dialogue on Grid Integration Issues hosted by NRECA (June 7, 2011).

“Overview of the Annual Looking Forward Report.” Presented to the SPP Board of Directors and Members Committee (April 26, 2011).

“America’s Energy and Climate Change Policy.” Published in *The Electricity Journal*, Volume 24, Issue 2, March 2011. ISSN 1040-6190.

“Summary of Recommendations in our Report: a Review of the Southwest Power Pool’s Integrated Marketplace Proposal.” Presented to the Southwest Power Pool Board of Directors and Members Committee (January 25, 2011).

“Look to the States: For America’s Climate Change Policy and Investment Opportunities.” Presented to the “The Politics and Economics of Climate Change” Conference hosted by IPPAI and NRRI (October 14, 2010).

“Headlines From The *2009 State Of The Market Report* Southwest Power Pool, Inc.” Presented to the Southwest Power Pool Board of Directors and Members Committee (April 27, 2010).

“Independent Review of SPP’S Cost/Benefit Study For The Priority Transmission Projects.” Presented to the Southwest Power Pool Board of Directors and Members Committee (April 27, 2010).

“Building Electric Transmission for Renewable Energy: Two Case Studies on Who Pays.” Presented to the American Bar Association (September 10, 2009).

“Financial Incentives for Utilities to Purchase Resources: The Right Reasons the Right Way.” Presented to the Harvard Electricity Policy Group Fifty-Second Plenary Session (October 3, 2008).

REDACTED

- “Boston Pacific’s Comments on NARUC [Competitive Bidding] Study” Submitted to NARUC (October 2008).
- “Financial Incentives for Utilities to Purchase Resources: The Right Reasons, The Right Way” Presented to Harvard Electricity Policy Group Fifty-Second Plenary Session, Chicago, Illinois (October 2008).
- “Market and Auction Monitoring: Requirements, Philosophy and Tools of the Trade” Presented to Edison Electric Institute Transmission and Wholesale Markets School, Madison, Wisconsin (August 2008).
- “Summary of the 2007 State of the Market Report for SPP’s EIS and Transmission Markets” Presented to Federal Energy Regulatory Commission (June 2008).
- “Summary of the 2006 State of the Market Report for SPP’s EIS and Transmission Markets” Presented to the Federal Energy Regulatory Commission (May 2007).
- “State-of-the-Art Fair Utility Procurement Practices: An Independent Monitor’s Perspective” Presented at the Northwest Independent Power Producers Coalition’s Annual Meeting, Union, WA (September 2005).
- “SPP Market Power Monitoring and Mitigation” Presented at the Energy Bar Association’s Midwest Conference, Kansas City, MO (March 2005).
- “Balance Sheet Penalties for Purchased Power” Presented at the Electric Power Supply Association’s Fall Membership Meeting, Washington, DC (November 2004).
- “Getting the Best Deal for Consumers: An Independent Monitor’s View” Presented at the Energy Bar Association’s Mid-Year Meeting, Washington, DC (November 2004).
- “Getting the Best Deal for Illinois Electric Customers” Presented at the Post 2006 Symposium, Chicago, IL (April 2004).
- “A Framework for Enhancing Reliability Through Consumer-Focused, Profitable Innovation” Presented at the National Electrical Manufacturers Association’s 2004 Spring Conference, Charleston, SC (April 2004).
- “Solicitations for Longer-Term Power Purchases” Presented at the Electric Power Supply Association’s Fall Membership Meeting, Washington, DC (October 2003).
- “Standards for Longer-Term Power Markets” Co-Presented at the North American Energy Standards Board’s Annual Meeting, Austin, TX (September 2003).
- “The Case for Competition in the U.S. Electricity Business,” The Electricity Journal Vol. 16 Issue 6 (2003), pp. 18-26.

REDACTED

“The Right Perspective and Right Tools for Risk Assessment” Presented at CBI’s Annual Conference on Private Power in Central America, Miami, Florida (June 2003).

“Standard Market Design (SMD): Helping Electricity Markets Work” Presented as a Briefing for Congressional Staff, Washington, DC (November 2002).

“Making Markets Work Under SMD” Presented at the Electric Power Supply Association’s Fall Membership Meeting, Washington, DC (October 2002).

“How Much Scrutiny is Too Much? How Much Control Can a Market Bear?” Presented at Walking the Beat: FERC as Market Monitor, A Platts Conference, Washington, DC (October 2002).

“Measuring Market Power in the U.S. Electricity Business,” Energy Law Journal 23, No.1 (2002), pp. 51-62.

“Market Monitoring and Market Power” Presented to the Energy Bar Association, Washington, DC (November 2001).

“Choosing a Market Power Standard for Market-Based Rates” Presented at the Electric Power Supply Association’s State Issues & Summer Membership Meeting, Washington, DC (July 2001).

“Energy Experts Debate Capping Electricity Prices in California,” The NewsHour with Jim Lehrer (May 2001).

“Price Caps: An Apparent Short-Term Solution That Creates Long-Term Problems” Presented at Energy and Power Risk Management’s Annual Conference, Houston, Texas (May 2001).

“Assuring Restructured Markets are Effectively Competitive” Presented to National Governors’ Association, Philadelphia, Pennsylvania (April 2001).

“Who Lost California?” Presented to Gulf Coast Power Association, Houston, Texas (March 2001).

“What Lessons Can New England Learn From California’s Wholesale Power Markets” Presented at Northeast Energy and Commerce Association’s Annual Meeting, Boston, Massachusetts (December 2000).

“Auction Debate: Last Price v. Pay-as-bid Auction Methods” Moderator and Speaker for the Electric Power Supply Association Regulatory Affairs Committee Meeting (December 2000).

“Congestion Management: Setting the Stage for Consensus” Moderator and Speaker for the Electric Power Supply Association Regulatory Affairs Committee Meeting (May 2000).

REDACTED

“Protecting the Consumer by Promoting Competition” Presented at “Trusting Markets-ISO Experiences” a workshop during the Electric Power Supply Association Fall Membership Meeting (October 1999).

“Renegotiating Power Purchase Agreements When Establishing Competitive Energy Markets” Presented at “Second Generation Issues in the Reform of Public Services” an international conference sponsored by the Inter-American Development Bank (October 1999).

“Presumptions About Customers That Drive Key Decisions in a Restructured Electricity Business” Presented at the Electric Power Supply Association/Fortune Magazine’s Executive Conference (January 1999).

“How External Factors Drive the Success of Your Investment and Strategic Decisions” Presented at the Electric Power Supply Association’s Risk Management Conference (December 1998).

“Assessing Market Power at the Retail Level” Presented at the Electric Power Supply Association’s Summer Membership Meeting (July 1998).

“The Right Market Power Analysis for Retail Restructuring Proceedings” Presented at the Electric Power Supply Association’s State and Regional Issues Meeting (March 1998).

“Managing Today’s Significant Risks” Presented at “International Power Project Development and Finance” (February 1998).

“Managing Today’s Significant Risks” Presented at the Electric Power Supply Association’s Risk Management Conference (December 1997).

“Managing Risk in a Restructured U.S. Electricity Business” Presented at the Council of Industrial Boiler Owners’ Annual Meeting (October 1997).

“A Risk Assessment Checklist for Power Project Acquisitions” Presented at “Mitigation Risk for International Power Projects” (July 1997).

“A Risk Assessment Checklist for International Power Projects” Presented at “Oil and Gas Companies in Global Power Project Development” (January 1997).

“A Risk Assessment Checklist for International Power Projects” Presented at “Financing Strategies for International IPP Projects” (November 1996).

“Addressing Municipalization and Bypass Concerns in a Restructured Electricity Business” Presented at EEI Municipalization and Bypass Conference (October 1996).

REDACTED

“Performance-Based Ratemaking in an Electricity Business Restructured for Competition” Presented at “Performance-Based Ratemaking for Electric & Gas Utilities” (October 1996).

“A Risk Assessment Checklist for International Power Projects” Presented at “Neutralizing Risk for International Power Projects” (September 1996).

“The Right Competitive Strategy For A Restructured U.S. Electricity Business” Presented at “POWER-GEN Americas ‘95” (December 1995).

“Practical Lessons Learned from Past Project Failures” Presented at “Risk Mitigation for International Power Projects” (November 1995).

“The Due Diligence Process: New Views for the Lender and Investor” Presented at “Project Finance Tutorial” (November 1995).

“State Regulatory Trends” Presented at “Electric Industry Restructuring: Understanding the Implications for the Natural Gas Industry” (October 1995).

“Summary of State of Competition Opinion Survey” Presented at NARUC Summer 1995 Committee Meeting (July 1995).

“Spin-Off Services of Retail Competition” Presented at “Giving Customers More Options: The Key to Success in the New Power Market” (May 1995).

“The Latin American Power Market” Presented at “New Opportunities in the Evolving World Power Market” (November 1994).

“Transmission Access and Pricing: Evolving Commercial and Regulatory Approaches” Presented at “Competitive Power Congress ‘94” (June 1994).

“Section 712: A Surprise Ending” Independent Energy (May/June 1994), pp. 55-59.

“Non-Traditional Competition For Industrial Loads” Presented to Oglethorpe Power (April 1994).

“Section 712: Southeast Roundup” Presented at “The Southeast Power Market in a New Age of Competition” Southeast Power Report and Independent Power Report (December 1993).

“The Emerging Latin American Power Market” Presented at “International Power Market” (December 1993).

“Structural Change in the Electricity Business” Presented at “Annual Fall Policy Roundtable” Council on Alternative Fuels (November 1993).

REDACTED

- “Power Project Siting and Community Relations: Six Elements of a Win-Win Strategy” (Coauthored) Cogeneration & Resource Recovery (July/August 1993).
- “How to Gain a Competitive Advantage in the Electricity Business” Presented at “Bidding For Power” The Institute For International Research (March 1993).
- “The Energy Policy Act of 1992: Its Effect on Market Opportunities in the Short- and Long-Run” Presented at “Market Opportunities for Utilities in the Energy Policy Act of 1992” Power Engineering and EL&P (February 1993).
- “Natural Gas v. Coal: Comparisons of Cost, Risk, and Environmental Performance” Institute of Public Utilities (December 1992).
- “How to Gain a Competitive Advantage in the Electricity Business” Presented at “Competitive Bidding for Power Contracts” Infocast (May and October 1991; March 1993).
- “Designing a Bidding System to Get the Best Deal for Ratepayers” Presented at “Competitive Bidding for Power Contracts” Infocast (May 1991).
- “Accommodating Renewables in Utility Bidding Systems: Toward a Level Playing Field” Institute of Public Utilities (December 1991).
- “The Successful Independent Power Producer” Presented at “Alternate Energy ‘90” Council on Alternate Fuels (April 1990).
- “Alternative Approaches to Transmission Access” Institute of Public Utilities (1988).
- “The Coming Boom in Computer Loads” (Coauthored) Public Utilities Fortnightly (December 1986), pp. 30-34.

BOOKS

- “Policy Models and Policymakers: The Case of Industrial Energy Use.” In Coal Models and Their Use in Government Planning, pp. 23-36. Edited by James Quirk, Katsuaki Terasawa, and David Whipple. New York: Praeger Publishers, 1982.
- “Coal Substitution.” In Energy-Policy Analysis and Congressional Action, pp. 97-113. Edited by Raymond C. Scheppach and Everett M. Ehrlich. Lexington, MA: D.C. Heath and Company, 1982.

CONSULTING REPORTS (PUBLIC ONLY)

REDACTED

Southwest Power Pool Annual Looking Forward Report. For the Southwest Power Pool Board of Directors, Washington, DC, [2014].

Annual Final Report on the 2013 BGS FP and CIEP Auctions. For the New Jersey Board of Public Utilities, Washington, DC, [2013].

Southwest Power Pool Annual Looking Forward Report. For the Southwest Power Pool Board of Directors, Washington, DC, [2013].

Annual Final Report on the 2012 BGS FP and CIEP Auctions. For the New Jersey Board of Public Utilities, Washington, DC, [2012].

Report of the Commission's Consultant Regarding FirstEnergy's 2011-2012 Standard Service Offer Auctions. For the Public Utilities Commission of Ohio, Washington, DC, [2012].

Southwest Power Pool Annual Looking Forward Report. For the Southwest Power Pool Board of Directors, Washington, DC, [2012].

Review of Terms and Conditions for Long-Term Contracts for Renewable Ocean Energy. For the Governor's Office of Energy Independence and Security for the State of Maine, Washington, DC, [2012].

Boston Pacific's Final Shortlist Evaluation. For the Maryland Public Service Commission, Washington, DC, [2012].

Evaluating the Economics of Offshore Wind Projects: Evaluation of the Application by Fishermen's Atlantic City Windfarm, LLC. For the State of New Jersey Board of Public Utilities Office of Clean Energy, Washington, DC, [2012]

Evaluation of a Draft Request for Proposals for Generating Capacity Resources Under Long-Term Contract. For the Maryland Public Service Commission, Washington, DC, [2012].

Report of the Commission's Consultant Regarding Duke Energy Ohio's Planned Standard Service Offer Auctions. For the Public Utilities Commission of Ohio, Washington, DC, [2012].

Southwest Power Pool Annual Looking Forward Report. For the Southwest Power Pool Board of Directors, Washington, DC, [2011].

Annual Final Report on the 2011 BGS FP and CIEP Auctions. For the New Jersey Board of Public Utilities. Washington, DC, [2011].

A Review of the Southwest Power Pool's Integrated Marketplace Proposal. For the Southwest Power Pool Board of Directors, Washington, DC, [2010].

REDACTED

Final Report of the Market Monitor on Potomac Electric Power Company's 2009-2010 Request for Proposals for Full Requirements Wholesale Supply to the District of Columbia's Standard Offer Service Customers. For the District of Columbia Public Service Commission. Washington, DC, [2010].

Final Report of the Technical Consultant on Delmarva's 2009-2010 Request for Proposals for Full Requirements Wholesale Electric Power Supply to Delaware's Standard Offer Service Customers. For the Delaware Public Service Commission. Washington, DC, [2010].

Annual Final Report on the 2010 BGS FP and CIEP Auctions. For the New Jersey Board of Public Utilities. Washington, DC, [2010].

The 2009 State of the Market Report, Southwest Power Pool, Inc. as an Advisor to the Southwest Power Pool Board of Directors. Washington, DC, [2010].

Report of the Commission's Consultant Regarding FirstEnergy's 2009 Standard Service Offer Auction. For the Public Utilities Commission of Ohio. Washington, DC, [2009].

The Oregon Independent Evaluator's Final Closing Report on PacifiCorp's 2008R-1 Renewables RFP. For the Oregon Public Utility Commission. Washington, DC, [2009].

Annual Final Report on the 2009 BGS FP and CIEP Auctions. For the New Jersey Board of Public Utilities. Washington, DC, [2009].

Final Report of the Market Monitoring Consultant on Potomac Electric Power Company's 2008-2009 Request for Proposals for Full Requirements Wholesale Supply to the District of Columbia's Standard Offer Service Customers. For the District of Columbia Public Service Commission. Washington, DC, [2009].

Final Report of the Technical Consultant on Delmarva's 2008-09 Request for Proposals for Full Requirements Wholesale Supply to Delaware's Standard Offer Service Customers. For the Delaware Public Service Commission. Washington, DC, [2009].

2008 State of the Market Report, Southwest Power Pool, Inc. For the Southwest Power Pool Board of Directors. Washington, DC, [2009].

An Analysis of PacifiCorp's Waiver Request for the Chehalis Power Generating Plant. For the Oregon Public Utility Commission. Washington, DC, [2008].

The Oregon Independent Evaluator's Assessment of PacifiCorp's 2008R-1 Renewables RFP Design. For the Oregon Public Utility Commission. Washington, DC, [2008].

Annual Final Report on the 2008 BGS FP and CIEP Auctions. For the New Jersey Board of Public Utilities. Washington, DC, [2008].

REDACTED

Final Report of the Technical Consultant on Potomac Electric Power Company's 2007-2008 Request for Proposals for Full Requirements Wholesale Supply to the District of Columbia's Standard Offer Service Customers. For the District of Columbia Public Service Commission. Washington, DC, [2008].

Final Report of the Technical Consultant on Delmarva's 2007-08 Request for Proposals for Full Requirements Wholesale Supply to Delaware's Standard Offer Service Customers. For the Delaware Public Service Commission. Washington, DC, [2008].

2007 State of the Market Report, Southwest Power Pool, Inc. For the Southwest Power Pool Board of Directors. Washington, DC, [2008].

The Oregon Independent Evaluator's Assessment of PacifiCorp's 2012 RFP Design, Part One: Evaluation Criteria, Methods and Computer Models. For the Public Utility Commission of Oregon. Washington, DC, [2007].

Final Report of the Technical Consultant on Potomac Electric Power Company's 2006-2007 Request for Proposals for Full Requirements Wholesale Supply to the District of Columbia's Standard Offer Service Customers. For the District of Columbia Public Service Commission. Washington, DC, [2007].

Final Report of the Technical Consultant on Delmarva's 2006-07 Request for Proposals for Full Requirements Wholesale Supply to Delaware's Standard Offer Service Customers. For the Delaware Public Service Commission. Washington, DC, [2007].

Final Report on the 2007 BGS FP and CIEP Auctions and the RECO SWAP RFP. For the New Jersey Board of Public Utilities. Washington, DC, [2007].

April 2007: Monthly Metrics Report. For the Southwest Power Pool (SPP) Energy Imbalance Services (EIS) Market. Washington, DC, [2007].

March 2007: Monthly Metrics Report. For the Southwest Power Pool (SPP) Energy Imbalance Services (EIS) Market. Washington, DC, [2007].

February 2007: Monthly Metrics Report. For the Southwest Power Pool (SPP) Energy Imbalance Services (EIS) Market. Washington, DC, [2007].

2006 State of the Market Report, Southwest Power Pool, Inc. For the Southwest Power Pool Board of Directors. Washington, DC, [2007].

2005 State of the Market Report, Southwest Power Pool, Inc. For the Southwest Power Pool Board of Directors. Washington, DC, [2006].

2004 State of the Market Report, Southwest Power Pool, Inc. For the Southwest Power Pool Board of Directors. Washington, DC, [2005].

REDACTED

Getting the Best Deal for Electric Utility Customers: A Concise Guidebook for the Design, Implementation, and Monitoring of Competitive Power Supply Solicitations. For the Electric Power Supply Association. Washington, DC, [2004].

Still Waters Run Deep. For the Electric Power Supply Association. Washington, DC, [2002].

Assessing the "Good Old Days" of Cost-Plus Regulation. For the Electric Power Supply Association. Washington, DC, [2001].

An Initial Analysis of Recent Wholesale Prices, Price Caps and Their Effect on Competitive Bulk Power Markets. For the Electric Power Supply Association. Washington, DC, [2000].

RTOs Must Manage Transmission, Not Power Markets. Facilitated by Boston Pacific for the Electric Power Supply Association. Washington, DC, [2000].

Competing For Global Power Projects: A White Paper on the Role of the Export-Import Bank of the United States and the Overseas Private Investment Corporation in the Global Electric Power Business. For the International Energy Development Council. Washington, DC, [1997].

Stating Their Differences: A Report on State Legislators' Views Concerning Electric Industry Restructuring. Washington, DC: Electric Generation Association, [1996].

The State of Competition: A Survey of State Commissions on Competition in the Electricity Business. Washington, DC: Electric Generation Association, [1995].

What Contribution Can Environmental Valuation Make to the Cost Competitiveness of Renewables in Current Bidding Systems for the Electricity Business? A Sourcebook for State Regulatory Commissions. For the Global Change Division, U.S. Environmental Protection Agency, [June 1991].

Electric Resources and Environmental Impacts. For the California Legislature's Joint Committee on Energy Regulation and the Environment. Sacramento, CA, [1990].

An Analysis of the Transmission Access and Pricing Policies of State Governments. Washington, DC: Boston Pacific Company, Inc., [1989].

Office Productivity Tools for the Information Economy: Possible Effects on Electricity Consumption. Palo Alto, CA: Electric Power Research Institute, [October 1988].

Competitive Procurement of Generating Capacity: Summary of Procedures in Selected States. For Office of Technology Assessment, U.S. Congress. Washington, DC: Boston Pacific Company, Inc., [1988].

REDACTED

Competitive Bidding in the Electricity Business: An Analysis of State Bidding Programs for QFs. Washington, DC: Boston Pacific Company, Inc., [1987].

Key Demographic Events for a Long-Term Forecast of Economic and Market Conditions. Palo Alto, CA: Electric Power Research Institute, [Working Paper 1985].

Transition to an Information Economy: Implications for the Electric Utility Industry. Palo Alto, CA: Electric Power Research Institute, [Working Paper 1984].

Coal Use by Industry: Forecasts and Analysis. Washington, DC: ICF Incorporated, [1982].

Prospects for Synthetic Fuels: Selected Topics. Washington, DC: ICF Incorporated, [1981].

A Policy Paper on the Environmental Consequences of the Emerging Synfuels Industry. Washington, DC: ICF Incorporated, [1980].

Methanol from Coal: Prospects and Performance as a Fuel and as a Feedstock. Washington, DC: ICF Incorporated, [1980].

A Report to the President's Commission on Coal: Possible Findings and Policy Recommendations for Hastening the Substitution of Coal for Imported Oil. Washington, DC: ICF Incorporated, [1979].

CONGRESSIONAL REPORTS

A Strategy for Oil Proliferation: Expediting Petroleum Exploration and Production in Non-OPEC Developing Countries. Washington, DC: The Congressional Budget Office, [1979].

Replacing Oil and Natural Gas with Coal: Prospects in the Manufacturing Industries. Washington, DC: The Congressional Budget Office, [1978].

President Carter's Energy Proposals: A Perspective (coauthored). Washington DC: The Congressional Budget Office, [1977].

Financing Waterway Development: The User Charge Debate. Washington, DC: The Congressional Budget Office, [1977].

Alton Locks and Dam: A Review of the Evidence. Washington, DC: The Congressional Budget Office, [1976].

DISSERTATION

REDACTED

Coal Use by Industry and the Associated Air Pollution Emissions in the Period From 1980 to 2000 Under Alternative Market and Regulatory Conditions. Madison, WI: University of Wisconsin.

Oklahoma Industrial Energy Consumers
Data Request OIEC-3
Cause No. PUD 201400229

3-12 Reference OG&E's response to OIEC 1-12 and Chart 3 on page 18 of Mr. Howell's direct testimony, provide the forecasted total annual nominal revenue requirements and 30-year cumulative NPV of revenue requirements for the selected Scrub/Convert portfolio and each alternative plan evaluated by OG&E for each year of the 2014 IRP analysis, for the base case and each sensitivity case evaluated, in an electronic format.

Response*: Please see **OIEC 1-11_Att** (files 1 through 35) and **OIEC 3-12_Att** (files 1 through 70) for the total annual nominal production cost and 30-year cumulative NPV of production cost for each of the Regional Haze Compliance Alternatives and expansion plan option in each scenario and sensitivity as described in OG&E's 2014 IRP Update. Please see **OIEC 3-12_Att** (Files 71 through 85) for the forecasted 30-year cumulative.

NPV of revenue requirements along with the total annual nominal return on rate base and expenses for each of the Regional Haze Compliance Alternatives and expansion plan option in each scenario and sensitivity as described in OG&E's 2014 IRP Update.

Response provided by:	<u>Leon Howell</u>
Response provided on:	<u>September 29, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

REDACTED

EXHIBIT CRR-2

CAUSE NO. PUD 201400229
 Data Request
 OIEC 3-12_Att71

Unit	Construction Years	Book Life	Tax Life	2014 \$	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5
----	0	0	0	\$ -					
Scrub Muskogee 4	4	25	20	\$ 289,053,005	22%	29%	13%	36%	0%
Scrub Muskogee 5	4	25	20	\$ 206,749,748	22%	29%	13%	36%	0%
Scrub Sooner 1	4	27	20	\$ 289,053,005	22%	29%	13%	36%	0%
Scrub Sooner 2	4	27	20	\$ 206,749,748	12%	16%	46%	26%	0%
Low NOx Burners, MK4	3	27	20	\$ 10,979,868	7%	82%	11%	0%	0%
Low NOx Burners, MK5	2	29	20	\$ 9,639,610	97%	3%	0%	0%	0%
Low NOx Burners, SN1	2	30	20	\$ 10,572,751	30%	70%	0%	0%	0%
Low NOx Burners, SN2	2	32	20	\$ 8,943,533	99%	1%	0%	0%	0%
Low NOx Burners Sem 1	4	20	20	\$ 20,108,134	3%	3%	41%	52%	0%
Low NOx Burners Sem 2	3	23	20	\$ 21,169,752	4%	26%	71%	0%	0%
Low NOx Burners Sem 3	5	23	20	\$ 18,996,713	3%	0%	4%	38%	54%
ACI Muskogee unit 4	3	3	Various	\$ 4,856,000	42%	50%	8%	0%	0%
ACI Muskogee unit 5	3	3	Various	\$ 4,856,000	42%	50%	8%	0%	0%
ACI Muskogee unit 6	3	34	20	\$ 4,856,000	42%	50%	8%	0%	0%
ACI Sooner unit 1	3	29	20	\$ 4,856,000	42%	50%	8%	0%	0%
ACI Sooner unit 2	3	30	20	\$ 4,856,000	42%	50%	8%	0%	0%
PSI Scrubber costs, 2015	1	27	20	\$ 5,244,661	100%				
Convert MK4 to Gas	2	24	20	\$ 35,736,522	25%	75%	0%	0%	0%
Convert MK5 to Gas	2	25	20	\$ 35,736,522	25%	75%	0%	0%	0%
Convert SN1 to Gas	2	26	20	\$ 35,736,522	25%	75%	0%	0%	0%
Convert SN2 to Gas	2	27	20	\$ 35,736,522	25%	75%	0%	0%	0%
New CC - 2x1 GE 7FA	5	35	20	\$ 689,634,686	4%	4%	12%	35%	45%
New CT - GE LM6000	4	35	20	\$ 39,210,661	4%	4%	18%	74%	0%

Total Tax Rate for ADIT	38.7590%
Return Rate on Investment with Taxes	11.7490%
Ad Valorem Tax Rate	1.0%
WACC	8.323%
Inflation	2.50%
Short Term Inflation	1.82%

Cashflows	2013	2014

Scrub Muskogee 4	-	-
Scrub Muskogee 5	-	-
Scrub Sooner 1	-	-
Scrub Sooner 2	-	-
Low NOx Burners, MK4	777,356	8,961,669
Low NOx Burners, MK5	9,360,997	278,613
Low NOx Burners, SN1	3,163,019	7,409,732
Low NOx Burners, SN2	8,855,517	88,016
Low NOx Burners Sem 1	696,135	535,510
Low NOx Burners Sem 2	765,350	5,467,634
Low NOx Burners Sem 3	601,004	45,521
ACI Muskogee unit 4	-	2,048,400
ACI Muskogee unit 5	-	2,048,400
ACI Muskogee unit 6	-	2,048,400
ACI Sooner unit 1	-	2,048,400
ACI Sooner unit 2	-	2,048,400
PSI Scrubber costs, 2015	-	-
Convert MK4 to Gas	-	-
Convert MK5 to Gas	-	-
Convert SN1 to Gas	-	-
Convert SN2 to Gas	-	-
New CC - 2018	27,092,308	27,585,388
New CC - 2019	-	27,585,388
New CC - 2020	-	-
New CC - 2023	-	-
New CC - 2024	-	-
New CC - 2025	-	-
New CC - 2028	-	-
New CC - 2031	-	-
New CC - 2035	-	-
New CC - 2037	-	-
New CC - 2039	-	-
New CC - 2041	-	-
New CC - 2043	-	-
New CC - 2044	-	-
New CT - 10 in 2018	-	15,684,265
New CT - 7 in 2018	-	10,978,985
New CT - 3 in 2019	-	-

REDACTED

EXHIBIT CRR-2

Cashflows	2039	2040	2041	2042	2043	2044

Scrub Muskogee 4	-	-	-	-	-	-
Scrub Muskogee 5	-	-	-	-	-	-
Scrub Sooner 1	-	-	-	-	-	-
Scrub Sooner 2	-	-	-	-	-	-
Low NOx Burners, MK4	-	-	-	-	-	-
Low NOx Burners, MK5	-	-	-	-	-	-
Low NOx Burners, SN1	-	-	-	-	-	-
Low NOx Burners, SN2	-	-	-	-	-	-
Low NOx Burners Sem 1	-	-	-	-	-	-
Low NOx Burners Sem 2	-	-	-	-	-	-
Low NOx Burners Sem 3	-	-	-	-	-	-
ACI Muskogee unit 4	-	-	-	-	-	-
ACI Muskogee unit 5	-	-	-	-	-	-
ACI Muskogee unit 6	-	-	-	-	-	-
ACI Sooner unit 1	-	-	-	-	-	-
ACI Sooner unit 2	-	-	-	-	-	-
PSI Scrubber costs, 2015	-	-	-	-	-	-
Convert MK4 to Gas	-	-	-	-	-	-
Convert MK5 to Gas	-	-	-	-	-	-
Convert SN1 to Gas	-	-	-	-	-	-
Convert SN2 to Gas	-	-	-	-	-	-
New CC - 2018	-	-	-	-	-	-
New CC - 2019	-	-	-	-	-	-
New CC - 2020	-	-	-	-	-	-
New CC - 2023	-	-	-	-	-	-
New CC - 2024	-	-	-	-	-	-
New CC - 2025	-	-	-	-	-	-
New CC - 2029	-	-	-	-	-	-
New CC - 2031	-	-	-	-	-	-
New CC - 2035	-	-	-	-	-	-
New CC - 2037	-	-	-	-	-	-
New CC - 2039	-	-	-	-	-	-
New CC - 2041	447,490,461	589,728,501	-	-	-	-
New CC - 2043	51,141,767	157,260,933	470,144,666	619,583,506	-	-
New CC - 2044	51,141,767	52,420,311	161,192,457	481,898,282	635,073,094	-
New CT - 10 in 2018	-	-	-	-	-	-
New CT - 7 in 2018	-	-	-	-	-	-
New CT - 3 in 2019	-	-	-	-	-	-

2014 Integrated Resource Plan - Update

OGE

CAUSE NO. PUD 201400229

Data Request

OIEC 3-12_Att86

Base Scenario

Portfolio: Spread CT

(\$Millions)	Scrub/ Convert				Scrub				Convert			
	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost
2015	17	282	864	1,163	21	283	864	1,168	13	282	864	1,158
2016	38	254	905	1,197	55	256	905	1,216	23	252	905	1,181
2017	76	263	947	1,286	105	265	947	1,317	51	260	947	1,258
2018	136	273	998	1,407	175	283	1,009	1,466	99	260	986	1,345
2019	193	272	1,156	1,622	242	322	1,080	1,643	144	231	1,233	1,607
2020	212	322	1,152	1,687	264	391	1,078	1,733	162	260	1,230	1,652
2021	210	352	1,194	1,757	258	424	1,115	1,797	162	297	1,277	1,736
2022	223	345	1,225	1,793	269	421	1,150	1,840	178	276	1,305	1,758
2023	254	344	1,262	1,860	297	428	1,188	1,913	211	275	1,347	1,833
2024	267	373	1,300	1,941	308	452	1,217	1,977	227	303	1,393	1,924
2025	259	406	1,356	2,020	297	490	1,269	2,056	220	337	1,457	2,015
2026	255	407	1,428	2,090	291	486	1,335	2,112	218	339	1,528	2,085
2027	268	467	1,480	2,216	302	539	1,382	2,223	234	416	1,597	2,247
2028	302	473	1,557	2,331	333	540	1,454	2,328	270	414	1,664	2,348
2029	313	463	1,602	2,378	342	543	1,483	2,368	283	398	1,725	2,406
2030	298	481	1,693	2,472	325	571	1,564	2,461	271	403	1,837	2,511
2031	287	510	1,836	2,633	311	577	1,708	2,597	261	463	1,974	2,699
2032	283	489	1,921	2,693	305	568	1,772	2,645	260	420	2,086	2,766
2033	302	517	2,043	2,862	322	592	1,882	2,796	281	461	2,211	2,954
2034	352	513	2,153	3,018	370	597	1,988	2,954	333	441	2,329	3,103
2035	401	526	2,237	3,164	416	628	2,056	3,100	384	445	2,451	3,280
2036	448	546	2,356	3,350	462	644	2,150	3,255	434	460	2,576	3,471
2037	495	596	2,417	3,507	506	705	2,215	3,426	482	511	2,631	3,624
2038	541	583	2,556	3,680	550	687	2,343	3,580	531	491	2,793	3,814
2039	589	646	2,625	3,861	596	743	2,411	3,750	581	569	2,875	4,025
2040	639	657	2,801	4,097	644	765	2,581	3,991	632	562	3,029	4,223
2041	691	690	2,905	4,287	695	803	2,654	4,153	686	603	3,165	4,454
2042	759	741	3,077	4,577	762	845	2,814	4,420	755	649	3,367	4,771
2043	824	770	3,262	4,856	826	846	3,134	4,805	821	676	3,533	5,030
2044	819	821	3,361	5,001	820	840	3,346	5,006	817	728	3,682	5,227
30 Yr NPVRR	2,596	4,216	15,540	22,351	2,919	4,821	14,683	22,423	2,276	3,699	16,509	22,484

CAUSE NO. PUD 201400229

Data Request

OIEC 3-12_Att86

Base Scenario

Portfolio: CC

2014 Integrated Resource Plan - Update

OGE

(\$Millions)	Scrub/ Convert				Scrub				Convert			
	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost
2015	24	283	864	1,172	29	284	864	1,177	20	283	864	1,167
2016	58	256	905	1,219	74	258	905	1,238	43	254	905	1,203
2017	105	266	947	1,318	134	267	947	1,349	80	263	947	1,290
2018	145	281	981	1,407	185	290	992	1,467	108	268	969	1,345
2019	162	278	1,141	1,580	210	327	1,065	1,602	113	236	1,218	1,566
2020	167	305	1,158	1,630	218	374	1,085	1,677	117	243	1,236	1,596
2021	186	326	1,201	1,713	234	398	1,122	1,754	138	271	1,283	1,692
2022	225	320	1,232	1,777	271	397	1,156	1,824	180	251	1,311	1,743
2023	262	341	1,244	1,847	305	426	1,170	1,901	219	273	1,329	1,821
2024	292	362	1,306	1,960	333	441	1,223	1,996	251	292	1,399	1,943
2025	302	406	1,336	2,044	340	491	1,249	2,081	264	338	1,437	2,039
2026	289	420	1,408	2,117	325	499	1,315	2,139	253	351	1,507	2,112
2027	279	477	1,460	2,216	313	548	1,362	2,223	245	425	1,576	2,247
2028	274	479	1,536	2,289	305	547	1,433	2,285	242	420	1,643	2,306
2029	287	445	1,609	2,342	317	526	1,490	2,332	258	380	1,732	2,370
2030	324	454	1,701	2,479	351	544	1,572	2,467	296	376	1,845	2,517
2031	340	511	1,810	2,661	364	578	1,682	2,625	314	465	1,948	2,727
2032	334	504	1,894	2,732	356	583	1,745	2,684	311	435	2,059	2,805
2033	351	532	2,016	2,898	371	608	1,854	2,832	330	476	2,184	2,989
2034	398	528	2,126	3,052	416	612	1,960	2,988	379	457	2,301	3,137
2035	444	542	2,208	3,194	460	644	2,026	3,130	428	460	2,421	3,309
2036	490	561	2,327	3,377	503	659	2,120	3,282	475	476	2,547	3,498
2037	534	611	2,386	3,531	545	721	2,184	3,450	522	526	2,600	3,648
2038	579	599	2,526	3,703	588	702	2,313	3,603	569	506	2,763	3,837
2039	626	661	2,594	3,881	633	758	2,379	3,770	618	584	2,843	4,045
2040	674	672	2,772	4,117	679	780	2,552	4,012	667	577	3,000	4,244
2041	724	705	2,877	4,306	728	818	2,626	4,171	718	618	3,136	4,472
2042	789	755	3,048	4,592	791	860	2,784	4,435	784	664	3,338	4,786
2043	852	785	3,236	4,873	853	860	3,109	4,822	849	691	3,507	5,047
2044	845	836	3,332	5,013	845	855	3,318	5,018	843	742	3,653	5,239
30 Yr												
NPVRR	2,729	4,214	15,432	22,375	3,052	4,819	14,576	22,446	2,409	3,696	16,402	22,507

CAUSE NO. PUD 201400229

Data Request

OIEC 3-12_Att86

Base Scenario

Portfolio: CT

(\$Millions)	Scrub/ Convert				Scrub				Convert			
	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost
2015	17	282	864	1,164	22	283	864	1,169	13	282	864	1,159

2014 Integrated Resource Plan - Update

OGE

2016	40	254	905	1,199	56	256	905	1,218	25	252	905	1,182
2017	82	264	947	1,293	112	266	947	1,324	58	261	947	1,266
2018	141	278	996	1,415	180	288	1,007	1,474	104	265	984	1,353
2019	192	274	1,156	1,622	241	324	1,080	1,644	143	232	1,233	1,608
2020	212	322	1,152	1,686	263	391	1,078	1,732	161	260	1,230	1,651
2021	209	352	1,194	1,756	257	424	1,115	1,796	161	297	1,277	1,735
2022	222	344	1,225	1,792	268	421	1,150	1,839	177	276	1,305	1,758
2023	253	343	1,262	1,859	296	428	1,188	1,913	210	275	1,347	1,832
2024	267	373	1,300	1,940	307	452	1,217	1,976	226	303	1,393	1,923
2025	258	406	1,356	2,019	296	490	1,269	2,055	220	337	1,457	2,014
2026	254	407	1,428	2,089	290	486	1,335	2,111	218	339	1,528	2,084
2027	268	467	1,480	2,215	301	539	1,382	2,222	234	416	1,597	2,246
2028	301	473	1,557	2,331	332	540	1,454	2,327	269	414	1,664	2,348
2029	312	463	1,602	2,377	341	543	1,483	2,368	283	398	1,725	2,406
2030	298	481	1,693	2,472	325	571	1,564	2,460	270	403	1,837	2,510
2031	286	510	1,836	2,632	311	577	1,708	2,596	261	463	1,974	2,698
2032	282	489	1,921	2,692	305	568	1,772	2,645	259	420	2,086	2,765
2033	302	516	2,043	2,861	322	592	1,882	2,796	281	461	2,211	2,953
2034	352	513	2,153	3,018	369	597	1,988	2,954	333	441	2,329	3,103
2035	400	526	2,237	3,164	416	628	2,056	3,100	383	445	2,451	3,279
2036	448	546	2,356	3,350	461	644	2,150	3,255	433	460	2,576	3,470
2037	494	595	2,417	3,507	505	705	2,215	3,425	482	511	2,631	3,624
2038	540	583	2,556	3,679	549	687	2,343	3,579	530	491	2,793	3,814
2039	589	646	2,625	3,860	596	743	2,411	3,749	581	569	2,875	4,024
2040	638	657	2,801	4,096	644	765	2,581	3,990	632	562	3,029	4,223
2041	691	690	2,905	4,287	695	803	2,654	4,152	686	603	3,165	4,453
2042	759	740	3,077	4,577	762	845	2,814	4,420	755	649	3,367	4,771
2043	824	770	3,262	4,856	825	846	3,134	4,805	821	676	3,533	5,030
2044	819	821	3,361	5,001	819	840	3,346	5,005	817	727	3,682	5,226
30 Yr NPVRR	2,601	4,221	15,538	22,361	2,925	4,826	14,682	22,432	2,282	3,704	16,507	22,493

2014 Integrated Resource Plan - Update

OGE

CAUSE NO. PUD 201400229

Data Request

OIEC 3-12_Att86

Base Scenario

Portfolio: Spread CT

(\$Millions)	Scrub/ Replace				Replace			
	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost
2015	27	284	864	1,174	32	284	864	1,180
2016	62	257	905	1,223	70	258	905	1,232
2017	138	269	947	1,354	175	275	947	1,397
2018	263	284	998	1,545	352	285	986	1,624
2019	353	297	1,100	1,750	463	284	1,120	1,866
2020	365	380	1,093	1,838	466	378	1,113	1,957
2021	355	402	1,133	1,891	452	397	1,155	2,003
2022	362	404	1,164	1,931	454	395	1,183	2,033
2023	386	402	1,201	1,988	475	392	1,224	2,090
2024	394	433	1,238	2,064	478	424	1,269	2,170
2025	379	462	1,289	2,130	460	450	1,325	2,235
2026	369	465	1,362	2,196	447	454	1,396	2,296
2027	377	504	1,413	2,294	451	489	1,462	2,402
2028	405	515	1,487	2,407	475	499	1,525	2,500
2029	410	508	1,529	2,447	478	489	1,578	2,544
2030	390	542	1,612	2,544	454	526	1,675	2,654
2031	373	540	1,755	2,668	433	525	1,812	2,770
2032	364	538	1,838	2,739	420	518	1,920	2,858
2033	377	550	1,960	2,887	431	529	2,044	3,003
2034	422	563	2,070	3,055	471	543	2,162	3,176
2035	464	584	2,148	3,196	511	560	2,272	3,342
2036	506	608	2,268	3,382	549	585	2,399	3,534
2037	547	652	2,325	3,524	586	624	2,447	3,658
2038	588	647	2,467	3,701	623	618	2,616	3,857
2039	632	690	2,535	3,857	665	656	2,694	4,015
2040	679	720	2,716	4,115	711	690	2,859	4,259
2041	729	748	2,822	4,299	759	720	2,998	4,477
2042	793	798	2,993	4,584	822	764	3,199	4,785
2043	856	846	3,185	4,887	883	809	3,380	5,072
2044	848	916	3,282	5,045	874	878	3,524	5,276
30 Yr NPVRR	3,602	4,623	15,005	23,229	4,282	4,515	15,439	24,237

CAUSE NO. PUD 201400229

Data Request

OIEC 3-12_Att86

Base Scenario

Portfolio: CC

2014 Integrated Resource Plan - Update

OGE

	Scrub/ Replace				Replace			
	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost
2015	34	284	864	1,183	40	285	864	1,189
2016	81	259	905	1,245	89	260	905	1,255
2017	167	272	947	1,386	205	277	947	1,429
2018	272	292	981	1,545	362	293	969	1,624
2019	322	302	1,085	1,709	431	289	1,105	1,825
2020	320	363	1,100	1,782	421	360	1,120	1,901
2021	331	376	1,140	1,847	428	371	1,161	1,960
2022	364	380	1,171	1,915	457	371	1,189	2,017
2023	394	399	1,183	1,976	483	389	1,206	2,078
2024	418	422	1,244	2,083	503	413	1,274	2,190
2025	422	463	1,270	2,155	503	451	1,305	2,259
2026	404	477	1,342	2,223	481	466	1,376	2,323
2027	388	513	1,393	2,293	462	498	1,441	2,402
2028	377	522	1,466	2,365	448	506	1,504	2,457
2029	385	491	1,535	2,411	452	471	1,585	2,508
2030	416	515	1,619	2,550	480	499	1,682	2,660
2031	426	542	1,729	2,696	486	526	1,786	2,798
2032	414	553	1,811	2,778	471	533	1,893	2,897
2033	426	566	1,932	2,923	479	544	2,016	3,039
2034	468	579	2,042	3,089	517	558	2,134	3,210
2035	508	599	2,118	3,225	554	575	2,242	3,372
2036	548	623	2,238	3,409	591	601	2,370	3,561
2037	587	667	2,294	3,548	626	640	2,416	3,681
2038	626	662	2,437	3,724	661	633	2,586	3,880
2039	669	705	2,503	3,877	702	671	2,662	4,036
2040	714	735	2,687	4,136	746	705	2,829	4,280
2041	761	763	2,793	4,317	791	735	2,969	4,495
2042	823	813	2,964	4,600	852	779	3,170	4,800
2043	883	860	3,160	4,904	911	824	3,355	5,089
2044	873	931	3,253	5,057	899	893	3,495	5,288
30 Yr								
NPVRR	3,735	4,621	14,898	23,253	4,415	4,513	15,332	24,260

CAUSE NO. PUD 201400229

Data Request

OIEC 3-12_Att86

Base Scenario

Portfolio: CT

	Scrub/ Replace				Replace			
	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost	Return on Rate Base	Expenses	Production Cost with Market Impact	Customer Cost
2015	27	284	864	1,175	33	284	864	1,181

2014 Integrated Resource Plan - Update

OGE

2016	63	257	905	1,225	71	258	905	1,234
2017	145	270	947	1,362	182	276	947	1,404
2018	268	289	996	1,553	357	290	984	1,632
2019	352	299	1,100	1,751	462	285	1,120	1,867
2020	364	380	1,093	1,837	465	378	1,113	1,956
2021	354	402	1,133	1,890	451	397	1,155	2,002
2022	361	404	1,164	1,930	453	395	1,183	2,032
2023	385	402	1,201	1,988	474	391	1,224	2,089
2024	393	433	1,238	2,063	478	424	1,269	2,170
2025	378	462	1,289	2,129	459	450	1,325	2,234
2026	368	464	1,362	2,195	446	454	1,396	2,295
2027	377	503	1,413	2,293	451	489	1,462	2,401
2028	404	515	1,487	2,407	475	499	1,525	2,499
2029	410	508	1,529	2,446	477	489	1,578	2,543
2030	390	542	1,612	2,544	453	525	1,675	2,654
2031	372	540	1,755	2,668	433	525	1,812	2,769
2032	363	538	1,838	2,739	420	518	1,920	2,857
2033	377	550	1,960	2,887	430	529	2,044	3,003
2034	421	563	2,070	3,054	471	543	2,162	3,175
2035	464	584	2,148	3,195	510	560	2,272	3,342
2036	506	608	2,268	3,382	549	585	2,399	3,533
2037	547	652	2,325	3,524	586	624	2,447	3,657
2038	587	647	2,467	3,701	623	617	2,616	3,856
2039	632	690	2,535	3,856	665	656	2,694	4,015
2040	678	720	2,716	4,115	711	690	2,859	4,259
2041	728	748	2,822	4,299	759	720	2,998	4,476
2042	793	798	2,993	4,584	822	763	3,199	4,785
2043	856	845	3,185	4,886	883	809	3,380	5,072
2044	847	916	3,282	5,045	873	878	3,524	5,275
30 Yr								
NPVRR	3,608	4,628	15,003	23,239	4,288	4,520	15,438	24,246

Oklahoma Corporation Commission
Data Request PUDKC-3
Cause No. PUD 201400229

- 3-8** The following data requests address the OG&E IRP Update and the National Research Council (NRC) Report, "Terrorism and the Electric Power Delivery System," referenced on pages 27-28 of the IRP Update.
- a.** Please confirm that the NRC Report does not mention, address or make any claims regarding, specifically, the Mustang units, Tinker Air Force Base, and/or OG&E.
 - b.** Is it OG&E opinion that the network resources at the Mustang site are somehow more important to system reliability than network resources at all other OG&E sites? If so, please provide any studies, reports, analysis, or other evidence that supports OG&E's opinion.
 - c.** Is it OG&E opinion that new combustion turbines at other sites, assuming needed transmission system upgrades are built to make such turbines network resources, could not match the contribution to system reliability provided by such turbines at the Mustang site? If so, please provide any studies, reports, analysis, or other evidence that supports OG&E's opinion.
 - d.** To what extent has OG&E considered expanded use of distributed generation and microgrids to mitigate the risks posed by "extreme conditions such as those identified in the [NRC Report]?" Please provide any evidence of OG&E's efforts.
 - e.** Does Tinker Air Force Base have backup power, either on-site or off-site? If so, has OG&E assessed the role of such backup in providing power to a load island that could include Tinker Air Force Base?

Response*:

- a. The NRC Report does not specifically mention, address or make any claims regarding the Mustang units, Tinker AFB and/or OG&E.
- b. All of OG&E's resources are important for system reliability. OG&E does not believe that any one generating resource is more important than its other units. However, as explained in the 2014 IRP Update, OG&E believes that utilizing the existing Mustang site to replace the reserve planning capacity being retired is prudent for a variety of operational reasons. See pages 27 and 28 of the 2014 IRP Update.
- c. No, combustion turbines located at another site could provide system reliability benefits comparable to the benefits of combustion turbines at the Mustang site. However any such site would have to be located in close proximity to OG&E load like the Mustang site.
- d. OG&E has not considered distributed generation or microgrids to mitigate the risks posed by "extreme conditions such as those identified in the NRC report."

- e. OG&E has generation at Tinker AFB. OG&E has not assessed whether Tinker AFB has additional backup power to supply a load island.

Response provided by: Robert Burch/Leon Howell
Response provided on: November 10, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-3
Cause No. PUD 201400229

3-9 Please provide the actual number of starts, by year and by unit, at the Mustang site for the past five years, and the number of starts that were forecast for the remaining life of each Mustang unit in the 2012 IRP and in the most recent 2014 IRP Update.

Response*: Please see OCC 3-9_Att1 for the actual number of starts. Please see OCC 3-9_Att2 for the forecasted number of starts for each Mustang unit in both the 2012 IRP and in the 2014 IRP Update. The number of starts for Mustang changed due to OG&E modeling the SPP IM in the 2014 IRP Update. So far in 2014, the Mustang units have been called upon more and have cycled more than originally expected. OG&E believes that this is due to a combination of reliability benefits and operating flexibility that the Mustang units offer.

Response provided by:	<u>Robert Burch/Leon Howell</u>
Response provided on:	<u>November 10, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.



Performance Summary Report

Monthly Gas Unit Report - All the GAS units in OG+E

Report Period:

Rollup Weighting:

Calculations done with NERC OMC conversion method. If there are OMC events,

Mustang Plant - Mustang 1		Starting		
DATE	Att	Act	Rel	
2009	15	15	100%	
2010	10	10	100%	
2011	8	8	100%	
2012	8	8	100%	
2013	8	7	88%	
2014	29	29	100%	
Unit Totals	78	77	99%	

Mustang Plant - Mustang 2		Starting		
DATE	Att	Act	Rel	
2009	15	15	100%	
2010	8	8	100%	
2011	6	6	100%	
2012	7	7	100%	
2013	11	11	100%	
2014	38	37	97%	
Unit Totals	85	84	99%	

Mustang Plant - Mustang 3		Starting		
DATE	Att	Act	Rel	
2009	3	3	100%	
2010	8	8	100%	
2011	7	7	100%	
2012	9	9	100%	
2013	5	5	100%	
2014	16	15	94%	
Unit Totals	48	47	98%	

Mustang Plant - Mustang 4		Starting		
DATE	Att	Act	Rel	
2009	7	7	100%	
2010	7	7	100%	
2011	8	8	100%	
2012	5	5	100%	
2013	12	12	100%	
2014	21	21	100%	
Unit Totals	60	60	100%	

REDACTED

EXHIBIT CRR-4

CAUSE NO. PUD 201400229

Data Request

OCC 3-9_Att2

Number of Starts from 2012 IRP

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Mustang 1	48	49	45									
Mustang 2	27	31	30	31	40							
Mustang 3	27	37	22	22	29	31	27	26				
Mustang 4	16	15	18	17	8	16	15	17	19	22	20	21

Number of Starts from 2014 IRP Update

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Mustang 1			0	0	0							
Mustang 2			0	4	8							
Mustang 3			1	2	2							
Mustang 4			1	2	2							

Oklahoma Corporation Commission
Data Request PUDKC-3
Cause No. PUD 201400229

- 3-4 Witness Burch, at Table 2, p. 10, describes the estimated costs of two SO2 control technologies for Sooner Unit 1: “WFGD” and “DFGD=SDA”. At p. 14, Burch states that “OG&E’s environmental compliance plan is to install CDS on Sooner Units 1 and 2...”.**
- a. Please confirm whether the dry FGD scrubber that OG&E intends to install can be categorized as CDS or SDA. Additionally, please confirm which dry FGD scrubber type is assumed in the cost estimates provided in OG&E’s data request responses AG 1-6_Att.xlsx tab “Scrubber Exhibit SDR-4” and OIEC 2-1_Att_Confidential.**
 - b. Please provide a full accounting of the costs of the dry FGD scrubber(s) that OG&E intends to install on Sooner Units 1 & 2 in the form of OG&E’s data request responses AG 1-6_Att.xlsx tab “Scrubber Exhibit SDR-4” and OIEC 2-1_Att_Confidential.**

Response*:

- a. OGE is installing circulating dry scrubbing (CDS) technology at Sooner.

The original cost estimates, as provided in a study by Sargent & Lundy and utilized in responses AG 1-6 and OIEC 2-10, were based on SDA equipment. However, as shown in Witness Burch’s testimony on page 12, the estimates referenced are for CDS equipment and were developed internally by OG&E’s major projects team. Since the time that Witness Burch filed Direct testimony, the Company has entered into contracts for the CDS scrubber equipment and is currently evaluating vendor pricing received by OG&E for the balance of plant and equipment installation. Current analysis indicates total cost for CDS equipment, including installation, is on target with the cost estimate for CDS scrubbers as stated in Witness Burch’s testimony on page 12.

- b. See 3-4(a).

Response provided by:	<u>Robert Burch</u>
Response provided on:	<u>November 10, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-2
Cause No. PUD 201400229

2-2 IRP Figure 9 displays the “Regional Haze Compliance Alternatives.” Was executing a purchase power agreement or acquisition of an existing combined-cycle power plant evaluated as an alternative? If not, why not? If so, please provide all documents related to that evaluation.

Response*: OG&E’s environmental compliance plan includes maintaining fuel diversity by retaining coal units at Sooner. OG&E is unaware of coal units being available for purchase power or acquisition in the SPP territory; consequently, the company ruled out coal-based PPAs or acquisitions as an alternative to scrubbing the Sooner units. OG&E’s plan for Muskogee units 4 and 5 is to maintain the capacity while converting those units to natural gas. As stated on page 48 of OG&E’s 2014 IRP Update, OG&E considered a 500MW combined-cycle plant as an alternative to the conversion of a Muskogee unit.” Please see **PUDKC 2-2_Att** for the analysis of that alternative.

Response provided by:	<u>Leon Howell</u>
Response provided on:	<u>October 28, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-1
Cause No. PUD 201400229

1-7 At page 25 and 26 of its IRP, OG&E references partial ownership in the Red Bud and McClain combined cycle plants. Would the purchase of 100% of either or both of these units be an alternative to meeting the regional haze rule and/or mercury and air toxics standards requirements? If not, why? If so, why was such a purchase not considered?

Response*: OG&E's partners have not expressed interest in selling their portions of the McClain and Redbud plants. It should be noted that OG&E's partners combined own approximate 670MW of capacity in Redbud and McClain and OG&E has 2000MW of coal unit capacity that must meet the SO2 portion of the Regional Haze rule.

Response provided by:	<u>Leon Howell</u>
Response provided on:	<u>October 23, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

**Oklahoma Cogeneration L.L.C.
Data Request Cogen-1
Cause No. PUD 201400229**

- 1-5 Reference the OG&E 2014 IRP, page 28, stating that “OG&E also determined that no CT’s are available for acquisition in the region.”**
- a. Provide all documentation and studies performed by or for OG&E supporting this conclusion.**
 - b. Provide any documentation or analysis performed by or for OG&E related to availability of CC’s available for acquisition in the region.**

Response*:

- a. OG&E came to this conclusion in the spring of 2014 based on OG&E’s experience in the SPP marketplace and its general knowledge of what generation resources were available at that time. To OG&E’s knowledge, no CTs are available for acquisition in the region as of the date of this response.
- b. OG&E is aware of one CC available for acquisition in the region. This entity approached OG&E with an unsolicited offer. OG&E is not aware of any other CC in the region that would be available for acquisition. Documentation related to the unsolicited offer is attached in **Cogen 1-5_Att_Confidential**.

Response provided by:	<u>Leon Howell</u>
Response provided on:	<u>October 8, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-4
Cause No. PUD 201400229

4-1 Reference OG&E's response to OIEC 3-12 and Chart 3 on page 18 of Mr. Howell's direct testimony, please provide the forecasted total annual NPV of revenue requirements in 2014 dollars for the selected Scrub/Convert portfolio and each alternative plan evaluated by OG&E for each year of the 2014 IRP analysis, for the base case and each sensitivity case evaluated, in an electronic format.

Response*: Please see OIEC 3-12_Att86 for the forecasted total NPV of customer costs in 2014 dollars for the selected Scrub/Convert portfolio and each alternative plan evaluated by OG&E. The annual nominal dollars are also provided in OIEC 3-12_Att86.

Response provided by: Leon Howell
Response provided on: November 20, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-1
Cause No. PUD 201400229

- 1-6 IRP pages 21-25 discuss a number of factors that impact OG&E's future load, including energy sales uncertainty, peak demand uncertainty, energy efficiency programs, and demand response programs.**
- a. Has OG&E conducted any sensitivities on its own load forecast? If so, please provide all relevant analysis. If not, please explain why OG&E did not conduct such a sensitivity and specifically why a sensitivity of OG&E's own load was deemed less relevant than a sensitivity reflecting a 10% reduction in SPP load.**
 - b. Please provide the results, in the same format used for the production costs provided in response to OIEC Data Request 1-11 and OIEC Data Request 3-12 and the revenue requirements provided in response to OIEC 3-12, of sensitivities of higher and lower OG&E load, for each of the five compliance alternatives discussed in the IRP.**

Response*:

- a. Yes, OG&E included a 10% reduction of its own load in the Low Load sensitivity. It is reasonable to assume the forces that would drive a 10% reduction of OG&E's load would have a similar impact on other load in the SPP. OG&E did not conduct high load sensitivity. OG&E believes a high load or a 10% load increase has a low probability of occurring therefore deemed it unnecessary.
- b. OG&E has not conducted additional analysis of high and low load beyond those provided.

Response provided by: Leon Howell
 Response provided on: October 23, 2014
 Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-3
Cause No. PUD 201400229

- 3-6 In 2013, Public Service of Oklahoma (PSO) issued a 2013 Plan Update to its 2012 IRP. In that document, PSO indicated that its capacity needs had increased because of new load from the oil and gas industry and changes to its estimates of demand side management (DSM) programs. The following questions ask to what extent similar issues may affect OG&E's load.
- a. Does OG&E have any studies, reports, analysis, or other evidence about how the results of its DSM and energy efficiency programs have compared to forecasted results? If so, please provide such evidence.
 - b. Has OG&E conducted any industry-specific approach to forecasting load, including a survey or outreach to potential new customers?
 - c. In the past 3 years, has OG&E had any conversations with potential new sources of load that are not reflected in OG&E's 2014 Integrated Resource Plan – Update? If so, please provide the name and type of such potential new sources of load, their size in MW of peak demand, and all meeting notes and presentations from such meetings.
 - d. In the past 3 years, has OG&E had conversations with current sources of load that might indicate that, in total, 10 MW or more of peak demand is considering leaving OG&E's system? If so, please provide the name and type of these sources of load, their size in MW of peak demand, and all meeting notes and presentations from such meetings.

Response*:

- a. Yes, please see **OCC 3-6_Att** for the 2013 Oklahoma Demand Programs Annual Report, which provides the results of OG&E's DSM and energy efficiency programs compared to its forecasts of DSM and energy efficiency savings. This file is located at <https://secure.oge.com/Envir2> UserID: Envir2 Password: Envirhttps@123.
- b. No, OG&E has not conducted any industry-specific approach to forecasting load, including a survey or outreach to potential new customers.
- c. OG&E's economic development office works with the Oklahoma Department of Commerce and the various communities OG&E serves to assist them in attracting or expanding job-creating investment. On a weekly basis, OG&E receives inquiries from its economic development partners (communities and the state) to respond to RFP's that often, but not always, have electric service and pricing questions. These projects are highly prospective and are often gathering information from multiple sites in multiple states. Ultimately, the project will reduce the number of potential sites through an analytical process that includes multiple criteria, with electric service and cost issues being only one. A very small number of them ever come to fruition in Oklahoma. These projects are typically identified by project name and are considered the confidential work

product of prospective customers and/or their consultants. The confidentiality issue presents a barrier to answering this question.

- d. In the past 5 years, OG&E has been working to eliminate wholesale energy contracts from its sales portfolio. Please see OG&E's 2014 IRP Update, Appendix A, page 19 for a list of expired or expiring wholesale contracts under the heading "FERC Demand."

Response provided by: Leon Howell
Response provided on: November 10, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-3
Cause No. PUD 201400229

- 3-1 Please provide the results, in the same format used for the production costs provided in response to (a) OIEC Data Request 1-11 and OIEC Data Request 3-12 and (b) the revenue requirements provided in response to OIEC 3-12, of a sensitivity that combines OG&E's high natural gas price sensitivity with its CO2 cost sensitivity, for each of the five compliance alternatives discussed in the IRP.**

Response*: The requested (a) production costs and (b) revenue requirements are not available. OG&E has not analyzed a situation where both high natural gas and CO2 costs both occur at the same time.

Response provided by: Leon Howell
Response provided on: November 10, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Corporation Commission
Data Request PUDKC-4
Cause No. PUD 201400229

- 4-6** The sensitivities in OG&E's 2014 IRP vary a single input at a time, such as natural gas prices or CO2 prices. Please provide two additional sensitivities that begin with the inputs used in OG&E's base case, spread CT sensitivity, but then adjust two or more of those inputs in each model run.
- a. A sensitivity that includes (a) OG&E's CO2 price sensitivity, (b) OG&E's high natural gas price sensitivity, (c) OG&E's high conversion rate sensitivity, and (d) an assumption that OG&E's retrofitted Sooner units are forced to retire in 2031.
 - b. A sensitivity with (a) OG&E's low SPP load sensitivity, and (b) an assumption of low OG&E's load. The magnitude of this lower OG&E load in each year, compared to the base case, should be the same as the change in SPP load in that low load sensitivity compared to the base case assumption of SPP load.

Response*:

- a. The requested analysis is not available. OG&E has not analyzed a situation where high natural gas prices, CO2 costs, high coal conversion to natural gas in SPP and OG&E's retrofitted Sooner units are forced to retire in 2031 all occur.
- b. See OG&E's response to **OCC 4-2**.

Response provided by:	<u>Leon Howell</u>
Response provided on:	<u>November 20, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Sierra Club
Data Request Sierra Club-1
Cause No. PUD 201400229

1-37 Refer to Data Response OIEC 1-11, Attachments 1 through 35. Please provide the following annually for each attachment:

- a. Variable O&M broken down for each environmental control (by unit)
- b. Fixed O&M (by unit)
- c. Depreciation (by unit)
- d. Interest costs (by unit)
- e. New build costs (by unit)
- f. Capital additions (by unit)
- g. Other fixed costs (by unit, if any)
- h. Calculations of “load cost” including supporting workpapers
- i. Calculations of “wind PPA” costs including supporting workpapers
- j. Calculations of “wind rev” including supporting workpapers
- k. Calculations of “GenRev” including supporting workpapers
- l. Hourly energy market prices
- m. Hourly generation (by unit)
- n. Calculations of CO₂ costs per unit (where applicable)
- o. Please confirm that CO₂ costs were included in hourly dispatch decisions.
 - If not, please explain how CO₂ costs were incorporated into the NPV analysis (where applicable)

Response*:

- a. The variable O&M cost (\$/MWhr) for each environmental control is provided in OG&E's 2014 IRP Update on page 29, Table 10: Emission Control Technologies. These costs are included in the individual unit O&M costs provided in **OIEC 1-11**.
- b. The Fixed O&M is provided in **OIEC 3-12_Att** (files 70-85).
- c. The depreciation is provided in **OIEC 3-12_Att** (files 70-85).
- d. There is no interest cost. OG&E assumes CWIP in its analysis.
- e. The new build cost is provided in **OIEC 3-12_Att** (files 70-85).
- f. The capital additions are provided in **OIEC 3-12_Att** (files 70-85).
- g. The other fixed costs are provided in **OIEC 3-12_Att** (files 70-85).
- h. Please see **Sierra 1-37_Att1_Confidential** for the calculations of the “load cost”.
- i. Please see **OIEC 3-21_Att2_Confidential** for the calculations of “wind PPA” costs.
- j. Please see **Sierra 1-37_Att2_Confidential** for the calculations of the “wind rev”.
- k. “GenRev” is an output of GenTrader and is provided in **OIEC 1-11** and **OIEC 3-12**.

- l. Please see Sierra 1-37_Att1_Confidential for the hourly energy market prices.
- m. Hourly modeling output data by unit for every alternative analyzed is not retained by the company in its modeling process due to the large amount of data. However, annual data by unit for every alternative is retained and has been provided in OIEC 1-11.
- n. The CO2 cost for each unit is imbedded in the fuel cost provided in OIEC 1-11_Att and OIEC 3-12_Att. OG&E does not have these cost separated for each unit.
- o. The CO2 prices were included in hourly dispatch decisions in the CO2 market price sensitivity.

Response provided by: Leon Howell
Response provided on: October 9, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

REDACTED

EXHIBIT CRR-14

[REDACTED – Sierra 1-37_Att1_Confidential]

Oklahoma Corporation Commission
Data Request OIEC-1
Cause No. PUD 201400229

1-25 Provide OG&E's base case and sensitivity case price forecasts for natural gas, coal and SPP market energy prices for each year of the Company's 2014 IRP analysis, along with supporting workpapers and the source of such forecasts.

Response*: Please see attachment **OIEC 1-25_Att1** for base case and sensitivity case price forecasts for natural gas and coal. Please see attachment **OIEC 1-25_Att2** for SPP market energy prices for each year of the Company's 2014 IRP analysis.

Response provided by: Leon Howell
Response provided on: August 28, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

REDACTED

EXHIBIT CRR-15

CAUSE NO. PUD 201400229

Data Request

OIEC 1-25_Att1

Base Forecast is used unless otherwise specified

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal (\$/MMBTU)	\$2.14	\$2.18	\$2.24	\$2.33	\$2.41	\$2.49	\$2.57	\$2.66	\$2.76	\$2.85	\$2.95	\$3.05	\$3.15	\$3.25	\$3.35	\$3.47	\$3.58
NG (\$/MMBTU)	\$4.23	\$4.38	\$4.74	\$5.26	\$5.42	\$5.33	\$5.58	\$5.66	\$5.84	\$6.17	\$6.45	\$6.71	\$6.99	\$7.28	\$7.66	\$8.09	\$8.43

Prices are from EIA's Annual Energy Outlook 2014

The source file is located: <http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=0-AEO2014&table=62-AEO2014>
Near bottom of chart under Fuel Prices (nominal dollars per million Btu)

For High Gas Sensitivity 1.5

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NG (\$/MMBTU)	\$6.35	\$6.57	\$7.12	\$7.88	\$8.13	\$7.99	\$8.36	\$8.48	\$8.77	\$9.26	\$9.67	\$10.07	\$10.49	\$10.92	\$11.49	\$12.13	\$12.65

For Low Gas Sensitivity 0.75

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NG (\$/MMBTU)	\$3.17	\$3.29	\$3.56	\$3.94	\$4.07	\$4.00	\$4.18	\$4.24	\$4.38	\$4.63	\$4.84	\$5.04	\$5.25	\$5.46	\$5.75	\$6.07	\$6.33

REDACTED

EXHIBIT CRR-15

CAUSE NO. PUD 201

Data Request

OIEC 1-25_Att1

Base Forecast is used unl

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal (\$/MMBTU)	\$3.69	\$3.81	\$3.92	\$4.05	\$4.18	\$4.31	\$4.45	\$4.60	\$4.75	\$4.90	\$5.06	\$5.22	\$5.38
NG (\$/MMBTU)	\$8.86	\$9.35	\$9.79	\$10.34	\$10.95	\$11.30	\$11.56	\$12.01	\$12.65	\$13.32	\$14.04	\$14.78	\$15.57

®ion=3-18&cases=ref2014-d102413a

For High Gas Sensitivity

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
NG (\$/MMBTU)	\$13.29	\$14.02	\$14.69	\$15.51	\$16.42	\$16.95	\$17.34	\$18.02	\$18.97	\$19.99	\$21.05	\$22.18	\$23.36

For Low Gas Sensitivity

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
NG (\$/MMBTU)	\$6.65	\$7.01	\$7.35	\$7.76	\$8.21	\$8.47	\$8.67	\$9.01	\$9.49	\$9.99	\$10.53	\$11.09	\$11.68

Oklahoma Energy Results
Data Request OER-2
Cause No. PUD 201400229

2-3 See Don Rowlett Testimony at Page 16, Line 10, through Page 18, Line 24. In light of OAC 165:35-38-4, please fully explain why OG&E has not filed “a request for a review of its rates pursuant to Section 152 of Title 17 of the Oklahoma Statutes.”

Response*: OG&E intends to meet the requirements of 17 O.S. 286, which states that a utility is required to “file a request for a review of its rates pursuant to Section 152 of this title no more than twenty-four (24) months after the utility begins recovering the costs through a periodic rate adjustment mechanism.” OG&E has indicated its intention to file a rate case after the conclusion of this cause.

Response provided by:	<u>Don Rowlett</u>
Response provided on:	<u>November 6, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Industrial Energy Consumers
Data Request OIEC-3
Cause No. PUD 201400229

3-2 Reference OG&E's response to OIEC 1-4, provide forecasted revenue requirements and rate impacts in the format presented in this response for the period 2025-2044.

Response*: Please see attachment OIEC 3-2_Att.

Response provided by: Sheri Richard
Response provided on: September 29, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Industrial Energy Consumers
Data Request OIEC-4
Cause No. PUD 201400229

4-9 Please reference p.10, line14. Is property tax computed each year on CWIP balances? If so, how is that amount excluded from pro forma operating expense in each rate case?

Response*: Yes. The EGP rider includes estimated property taxes that are based on the utility plant balances, including any CWIP, that exist at the end of the prior calendar year.

For any subsequent base rate case, any property taxes that are or will be recovered through the EGP rider during the test year including any pro forma period will be excluded from pro forma operating expense, if the associated plant and CWIP balances remain in the EGP rider revenue requirement calculation. If the associated plant balances and CWIP are included in base rate calculations and removed from the rider, no such pro forma is needed.

Response provided by:	<u>Sheri Richard</u>
Response provided on:	<u>September 30, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Attorney General
Data Request AG-1
Cause No. PUD 201400229

1-6 Please provide an analysis in the format of the file titled “SRD-4 Summary Revenue Requirement” showing separately the revenue requirement for the replacement of the Mustang units, the ACI upgrades, the Muskogee fuel conversion, and the Sooner scrubbers.

Response*: Please see AG 1-6_Att.

Response provided by: Sheri Richard
Response provided on: October 6, 2014
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

REDACTED

EXHIBIT CRR-19

EXHIBIT SDR-4
Mustang CT's Only

OKLAHOMA GAS AND ELECTRIC COMPANY
Mustang CT's Environmental Project Revenue Requirement

LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
Rate Base						
1	Utility Plant	\$ 13.6	\$ 44.9	\$ 160.3	\$ 341.8	\$ 410.1
2	Accumulated Provision for Depreciation	-	-	-	(2.4)	(12.6)
3	Regulatory Assets	-	-	-	-	-
4	ADIT	-	-	-	(0.6)	(4.3)
5	Total Rate Base	\$ 13.6	\$ 44.9	\$ 160.3	\$ 338.8	\$ 393.2
6	Less Credit for Plant in Base Rates	-	-	-	-	-
7	Return on Rate Base	\$ 1.6	\$ 5.3	\$ 18.8	\$ 39.7	\$ 46.1
Expenses						
8	O&M Expense	\$ -	\$ -	\$ -	\$ 5.2	\$ 10.2
9	Depreciation Expense	-	-	-	6.4	12.4
10	Depr. Expense Unrecovered Mustang Plant	-	-	-	-	-
11	Amortization of Regulatory Assets	-	-	-	-	-
12	Property Taxes	0.1	0.2	0.6	2.4	3.8
13	Total Expenses	\$ 0.1	\$ 0.2	\$ 0.6	\$ 14.0	\$ 26.4
14	Revenue Requirement @ 100%	\$ 1.7	\$ 5.5	\$ 19.4	\$ 53.7	\$ 72.5
15	OK Revenue Requirement	\$ 1.5	\$ 4.9	\$ 17.4	\$ 48.1	\$ 64.9
16	Credit for O&M in Base Rates	-	-	-	-	-
17	OK Revenue Requirement with Credits	\$ 1.5	\$ 4.9	\$ 17.4	\$ 48.1	\$ 64.9

* May not add down due to rounding.

AG 1-6
CT's Only

REDACTED

EXHIBIT CRR-19

EXHIBIT SDR-4
ACI Only

OKLAHOMA GAS AND ELECTRIC COMPANY
ACI Environmental Project Revenue Requirement

LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
	Rate Base					
1	Utility Plant	\$ 15.0	\$ 24.4	\$ 24.6	\$ 24.6	\$ 24.6
2	Accumulated Provision for Depreciation	-	(1.9)	(5.5)	(9.1)	(11.0)
3	Regulatory Assets	-	-	-	-	-
4	ADIT	-	0.5	1.4	1.9	(0.8)
5	Total Rate Base	\$ 15.0	\$ 23.1	\$ 20.5	\$ 17.3	\$ 12.9
6	Less Credit for Plant in Base Rates	-	-	-	-	-
7	Return on Rate Base	\$ 1.8	\$ 2.7	\$ 2.4	\$ 2.0	\$ 1.5
	Expenses					
8	O&M Expense	\$ -	\$ 0.8	\$ 0.9	\$ 0.9	\$ 0.5
9	Depreciation Expense	-	3.6	3.6	3.6	0.3
10	Depr. Expense Unrecovered Mustang Plant	-	-	-	-	-
11	Amortization of Regulatory Assets	-	-	-	-	-
12	Property Taxes	0.1	0.2	0.2	0.2	0.2
13	Total Expenses	\$ 0.1	\$ 4.6	\$ 4.7	\$ 4.8	\$ 1.1
14	Revenue Requirement @ 100%	\$ 1.8	\$ 7.3	\$ 7.1	\$ 6.8	\$ 2.6
15	OK Revenue Requirement	\$ 1.7	\$ 6.6	\$ 6.4	\$ 6.1	\$ 2.3
16	Credit for O&M in Base Rates	-	-	-	-	-
17	OK Revenue Requirement with Credits	\$ 1.7	\$ 6.6	\$ 6.4	\$ 6.1	\$ 2.3

* May not add down due to rounding.

AG 1-6
ACI Only

REDACTED

EXHIBIT CRR-19

EXHIBIT SDR-4
Muskogee Gas Conversion

OKLAHOMA GAS AND ELECTRIC COMPANY
Muskogee Gas Conversion Project Revenue Requirement

LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
Rate Base						
1	Utility Plant	\$ -	\$ -	\$ 10.2	\$ 50.1	\$ 76.5
2	Accumulated Provision for Depreciation	-	-	-	-	(0.8)
3	Regulatory Assets	-	-	-	-	32.4
4	ADIT	-	-	-	-	(0.3)
5	Total Rate Base	\$ -	\$ -	\$ 10.2	\$ 50.1	\$ 107.7
6	Less Credit for Plant in Base Rates	-	-	-	-	-
7	Return on Rate Base	\$ -	\$ -	\$ 1.2	\$ 5.9	\$ 12.6
Expenses						
8	O&M Expense	\$ -	\$ -	\$ -	\$ -	\$ -
9	Depreciation Expense	-	-	-	-	1.6
10	Depr. Expense Unrecovered Mustang Plant	-	-	-	-	-
11	Amortization of Regulatory Assets	-	-	-	-	5.9
12	Property Taxes	-	-	-	0.2	0.8
13	Total Expenses	\$ -	\$ -	\$ -	\$ 0.2	\$ 8.3
14	Revenue Requirement @ 100%	\$ -	\$ -	\$ 1.2	\$ 6.1	\$ 20.9
15	OK Revenue Requirement	\$ -	\$ -	\$ 1.1	\$ 5.4	\$ 18.7
16	Credit for O&M in Base Rates	-	-	-	-	-
17	OK Revenue Requirement with Credits	\$ -	\$ -	\$ 1.1	\$ 5.4	\$ 18.7

* May not add down due to rounding.

AG 1-6

Muskogee Gas Conversion Only

REDACTED

EXHIBIT CRR-19

EXHIBIT SDR-4
Scrubber

OKLAHOMA GAS AND ELECTRIC COMPANY
Scrubber Project Revenue Requirement

LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
	Rate Base					
1	Utility Plant	\$ 38.5	\$ 131.7	\$ 223.8	\$ 373.8	\$ 517.9
2	Accumulated Provision for Depreciation	-	-	-	(4.7)	(28.0)
3	Regulatory Assets	-	-	-	-	-
4	ADIT	-	-	-	0.2	0.1
5	Total Rate Base	\$ 38.5	\$ 131.7	\$ 223.8	\$ 369.3	\$ 490.0
6	Less Credit for Plant in Base Rates	-	-	-	-	-
7	Return on Rate Base	\$ 4.5	\$ 15.4	\$ 26.2	\$ 43.3	\$ 57.4
	Expenses					
8	O&M Expense	\$ -	\$ -	\$ -	\$ 4.8	\$ 12.8
9	Depreciation Expense	-	-	-	11.7	30.5
10	Depr. Expense Unrecovered Mustang Plant	-	-	-	-	-
11	Amortization of Regulatory Assets	-	-	-	-	-
12	Property Taxes	-	0.7	1.8	2.6	4.7
13	Total Expenses	\$ -	\$ 0.7	\$ 1.8	\$ 19.1	\$ 48.1
14	Revenue Requirement @ 100%	\$ 4.5	\$ 16.1	\$ 28.0	\$ 62.4	\$ 105.5
15	OK Revenue Requirement	\$ 4.0	\$ 14.4	\$ 25.1	\$ 55.9	\$ 94.4
16	Credit for O&M in Base Rates	-	-	-	-	-
17	OK Revenue Requirement with Credits	\$ 4.0	\$ 14.4	\$ 25.1	\$ 55.9	\$ 94.4

* May not add down due to rounding.

AG 1-6
Scrubber Project Only

REDACTED

EXHIBIT CRR-19

EXHIBIT SDR-4
Low NO_x

OKLAHOMA GAS AND ELECTRIC COMPANY
Low NO_x Environmental Project Revenue Requirement

LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
Rate Base						
1	Utility Plant	\$ 63.2	\$ 81.1	\$ 98.0	\$ 99.4	\$ 99.4
2	Accumulated Provision for Depreciation	(1.3)	(2.8)	(5.0)	(7.6)	(10.1)
3	Regulatory Assets	-	-	-	-	-
4	ADIT	(1.1)	(2.0)	(3.3)	(4.7)	(6.0)
5	Total Rate Base	\$ 60.8	\$ 76.3	\$ 89.6	\$ 87.2	\$ 83.3
6	Less Credit for Plant in Base Rates	-	-	-	-	-
7	Return on Rate Base	\$ 7.1	\$ 8.9	\$ 10.5	\$ 10.2	\$ 9.8
Expenses						
8	O&M Expense	\$ -	\$ -	\$ -	\$ -	\$ -
9	Depreciation Expense	1.1	1.9	2.5	2.5	2.5
10	Depr. Expense Unrecovered Mustang Plant	-	-	-	-	-
11	Amortization of Regulatory Assets	-	-	-	-	-
12	Property Taxes	0.4	0.7	0.9	1.0	1.0
13	Total Expenses	\$ 1.4	\$ 2.6	\$ 3.4	\$ 3.5	\$ 3.5
14	Revenue Requirement @ 100%	\$ 8.5	\$ 11.5	\$ 13.9	\$ 13.7	\$ 13.3
15	OK Revenue Requirement	\$ 6.6	\$ 10.3	\$ 12.4	\$ 12.3	\$ 11.9
16	Credit for O&M in Base Rates	-	-	-	-	-
17	OK Revenue Requirement with Credits	\$ 6.6	\$ 10.3	\$ 12.4	\$ 12.3	\$ 11.9

* May not add down due to rounding.

AG 1-6
Low NO_x Only

**Oklahoma Industrial Energy Consumers
Data Request OIEC-11
Cause No. PUD 201400229**

11-1 Provide the forecasted in-service dates of environmental control systems which OG&E seeks to recover through its proposed EGP Rider.

Response*: See current forecasted in service dates:
 MK4 LNB – May 2015
 MK5 LNB – Installed
 SM2 LNB – May 2015
 SM1 LNB – April 2016
 SM3 LNB – April 2017*
 MK4 & MK5 conversion – May 2019**
 MK ACI – October 2015
 SO 1 & 2 LNB--Installed
 SO1 FGD – May 2018
 SO2 FGD – December 2018
 SO ACI – October 2015

* Unit will be in outage on the RH NOx compliance date. Unit will return to service with LNBs installed and in compliance.

** Units will be removed from service prior to the January 4, 2019 SO2 compliance date and gas conversion outages performed and units back in service by May, 2019.

Response provided by:	<u>Robert Burch</u>
Response provided on:	<u>December 8, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.

Oklahoma Energy Results
Data Request OER-1
Cause No. PUD 201400229

1-12 See Don Rowlett Direct Testimony at Page 2, Lines 10 and 11, See also page 16 at line 12 through page 18, line 18. Do Mr. Rowlett and OG&E agree that OG&E's proposed cost tracking for the Environmental Compliance Plan and the Mustang Modernization Plan will guarantee recovery of those costs and that such recovery is fundamentally different than base rate recovery which does not guarantee cost recovery—but rather allows a reasonable opportunity for cost recovery (including a reasonable opportunity to earn a reasonable return)?

Response*: No. The premise of the question incorrectly characterizes the nature of uncertainty associated with the utility's recovery of costs through authorized rates.

Response provided by:	<u>Don Rowlett</u>
Response provided on:	<u>October 24, 2014</u>
Contact & Phone No:	<u>Sheri Richard 405-553-3747</u>

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.