

BEFORE THE 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) CAUSE NO. PUD 201400229
CLEAN AIR ACT AND COST RECOVERY;)
AND FOR APPROVAL OF THE MUSTANG)
MODERNIZATION AND COST RECOVERY)

FILED
DEC 16 2014

RESPONSIVE TESTIMONY OF

JUDAH L. ROSE

MANAGING DIRECTOR

ICF INTERNATIONAL

COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

ON BEHALF OF

OKLAHOMA ENERGY RESULTS, LLC

DECEMBER 16, 2014

PUBLIC REDACTED VERSION

1 **I. INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

3 **A.** My name is Judah L. Rose. I am a Managing Director of ICF International (“ICF”). My
4 business address is 9300 Lee Highway, Fairfax, Virginia 22031.

5 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND,**
6 **PROFESSIONAL QUALIFICATIONS, AND EMPLOYMENT EXPERIENCE.**

7 **A.** After receiving a degree in economics from the Massachusetts Institute of Technology
8 and a Master’s Degree in Public Policy from the John F. Kennedy School of Government
9 at Harvard University, I have worked at ICF for over 32 years. I am a Managing Director
10 and co-chair of ICF’s Energy Advisory and Solutions practice. I have also served as a
11 member of the Board of Directors of ICF International and am one of three people among
12 ICF’s roster of approximately 5,000 professionals to have received ICF’s honorary title of
13 Distinguished Consultant.

14 **Q. WHAT IS ICF INTERNATIONAL?**

15 **A.** ICF International (NASDAQ:ICFI) provides professional services and technology
16 solutions across 13 market areas. Our advisory and implementation services assist clients
17 in strategy and policy analysis, program management, project evaluation, and other
18 services. Our energy practice employs top experts who use an integrated approach to
19 energy markets, applying cutting-edge technical skills and proprietary modeling tools to
20 provide clients with a complete picture of the energy landscape — from electric power to
21 fuels to renewables.

1 **Q. WHO ARE ICF'S CLIENTS?**

2 **A.** In the public sector, ICF has been the principal power consultant to the U.S.
3 Environmental Protection Agency ("EPA") for 40 years, specializing in the analysis of
4 air emission programs, especially cap and trade programs. We also have worked with the
5 Federal Energy Regulatory Commission ("FERC") on transmission issues and the U.S.
6 Department of Energy ("DOE") on energy security. In addition, we have worked with
7 state regulators and energy agencies, including those in California, Connecticut,
8 Kentucky, New Jersey, New York, Ohio, Texas, and Michigan, as well as with numerous
9 foreign governments.

10 In the private sector, for over 40 years, ICF has provided forecasts and other consulting
11 services to major United States and Canadian electric utilities. In the United States, ICF
12 has worked with utilities such as AES, American Electric Power, Allegheny, Arizona
13 Power Service, Dominion Power, Delmarva Power & Light, Dominion, Duke Energy,
14 FirstEnergy, Entergy, Exelon, Florida Power & Light, Long Island Power Authority,
15 National Grid, Northeast Utilities, Southern California Edison, Sempra, PacifiCorp,
16 Pacific Gas and Electric, Public Service Electric and Gas, PEPCO, Public Service of New
17 Mexico, Nevada Power and Tucson Electric. ICF also works with Regional
18 Transmission Organizations ("RTOs") and similar organizations, including the Midwest
19 Independent Transmission System Operator ("Midwest ISO"), the Electric Reliability
20 Council of Texas, the Western Electric Coordinating Council, WestConnect, and the
21 Florida Regional Coordinating Council.

1 **Q. WHAT TYPE OF WORK DO YOU TYPICALLY PERFORM?**

2 **A.** I have extensive experience in utility planning and in assessing wholesale electric power
3 markets and regulation. This includes forecasting wholesale electricity prices, power
4 plant operations and revenues, transmission flows, and fuel prices (e.g., coal, natural gas).
5 I also have extensive experience in assessing environmental regulations and their impacts
6 on supply and demand conditions in wholesale power markets, as well as on valuing
7 individual power plants in the context of projected market conditions.

8 **Q. WHAT EXPERIENCE DO YOU HAVE IN PROVIDING EXPERT TESTIMONY**
9 **RELATING TO THE POWER SECTOR?**

10 **A.** I have testified before or made presentations to the FERC, an international arbitration
11 tribunal, federal courts, arbitration panels, and before state regulators and legislators in 24
12 U.S. states and Canadian provinces: Arizona, Arkansas, California, Connecticut, Florida,
13 Indiana, Kentucky, Louisiana, Manitoba, Massachusetts, Minnesota, Missouri, Nevada,
14 New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Quebec, Rhode
15 Island, South Carolina, Texas, and West Virginia. I have testified extensively as to
16 electric power prices and markets, power purchase agreements, utility planning, and the
17 development and acquisition of new generation resources and transmission. In addition, I
18 have authored numerous articles in industry journals and spoken at scores of industry
19 conferences. For specific details, please see my resume, attached hereto as Attachment
20 A.

21 **Q. HAVE YOU TESTIFIED PREVIOUSLY IN THE STATE OF OKLAHOMA?**

22 **A.** Yes. I have testified in Oklahoma many times. *See* my resume in Attachment A.

1 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

2 **A.** I am testifying on behalf of Oklahoma Energy Results (“OER”).

3 **II. EXECUTIVE SUMMARY**

4 **Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.**

5 **A.** Oklahoma Gas and Electric (“OGE”) has a January 4, 2019 deadline for compliance with
6 Regional Haze regulations. OGE exhausted its ability to appeal certain aspects of these
7 regulations approximately six months ago in late May 2014. On August 6, 2014, OGE
8 filed its application with the Oklahoma Corporation Commission (“OCC”) in Cause PUD
9 01400229 requesting approval of its environmental compliance plan and recovery of
10 associated costs through the Environmental and Generation Plan (“EGP”) rider, approval
11 of OGE’s plan to construct new capacity consisting of Combustion Turbines (“CTs”) at
12 the Mustang generating site, and approval of recovery of costs associated with Mustang
13 retirement/replacement through the EGP rider, as well as various other matters. On
14 August 7, 2014, OGE release its Integrated Resource Plan (IRP) Update (“IRP”).

15 My review of OGE’s planning situation with an emphasis on its proposal for compliance
16 with Regional Haze regulations leads to the following conclusions:

- 17 ■ OGE did not conduct RFPs or even update RFIs for Production Tax Credit
18 (“PTC”) qualified wind and existing natural gas power plants. OGE did not
19 quantitatively analyze PTC qualified wind options nor did it analyze existing
20 natural gas power plant options. ICF analyzed the expected costs of these options
21 and found alternatives with substantially lower calculated costs.

1 ■ ICF's modeling conclusions show large savings of \$3.0 to \$3.3 billion when
2 comparing our modeling of OGE's IRP Capacity Expansion Plan (Scrub/Convert)
3 course of action with the 100% PTC cases. Our results show that combinations of
4 PTC qualified wind and gas generation could prove to be economically
5 advantageous to OGE customers. Both generation sources have the benefit of
6 recent improvements in technology and these changes could result in efficiency
7 gains. In light of finding large potential expected savings, the full and complete
8 assessment of the availability of PTC qualified wind while maintaining reserve
9 margin requirements is critical and OGE must complete this assessment before
10 proceeding under its proposed IRP. RFPs that provide market tests of PTC
11 qualified wind and for existing natural gas plant are necessary to determine lowest
12 costs to OGE's customers. Without including this more comprehensive
13 assessment into OGE's IRP process, including quantitative analysis of the energy
14 contributions of PTC qualified wind, and combinations of PTC qualified wind and
15 natural gas power plants, and associated transmission considerations, an IRP
16 process that requires consideration of least cost criteria is fatally flawed.

17 ■ Based on a conversation with [REDACTED] of wind
18 was identified in Oklahoma and nearby areas as currently qualifying for the PTC.

[REDACTED]

[REDACTED]

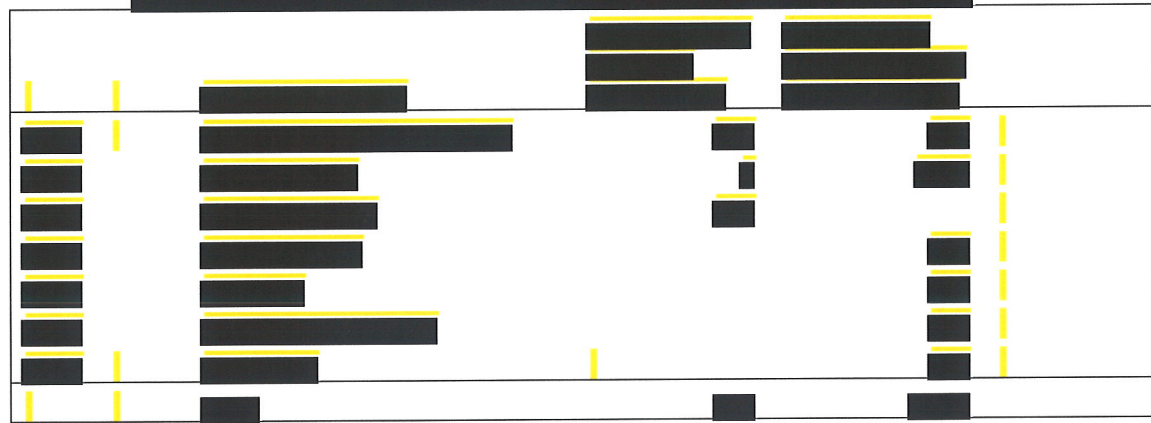
[REDACTED]

[REDACTED]

4 [REDACTED] (See Exhibit ICF-1). There may also be other
5 wind facilities in the Southwest Power Pool system (“SPP”) outside the nearby
6 area that currently qualify for the PTC or may qualify in the immediate future. In
7 addition, there is active consideration in the US Congress of an extension of the
8 PTC including a proposal that would qualify wind power plants under
9 construction by the end of 2014⁴.

Exhibit ICF-1 [REDACTED]

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[REDACTED]

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■ Depending on the amount of PTC qualified wind in Oklahoma and adjacent areas,

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ICF’s analysis indicates very large customer savings. The potential savings are in

[REDACTED]

⁴ Whenever I refer to available PTC qualified wind, I am referring to those qualified as of early December 2014 or as a result of an extension in the immediate future – e.g. an extension in late 2014 or early 2015 – unless otherwise stated.

1 proportion to the amount of PTC qualified wind available. For example, in a
2 scenario with 1900 MW⁵ of PTC qualified wind in combination with existing and
3 new gas fired power plants, the Net Present Value of Savings of Adjusted
4 Production Costs (APC) compared to the OGE IRP plan is approximately \$3.0 to
5 \$3.3 billion (2015\$). Other scenarios modeled by ICF including less PTC
6 qualified wind exhibit lower levels of savings to customers.

7 ■ Thus, the ICF analysis confirms that to the extent that it is available, the federal
8 PTC for wind power plants of approximately 2.3 cents per kilowatt hour creates
9 very significant customer cost savings opportunities, especially when combined
10 with high capacity factor wind.

11 ■ Furthermore, multiple natural gas generation options are projected to be available
12 to back up wind with natural gas power plants including existing units within the
13 SPP area.

14 ■ This finding is also consistent with OGE being the primary SPP load serving
15 entity located very close to outstanding wind resources. Hence, OGE has unique
16 opportunities to use this resource (see Exhibit ICF-2 and Exhibit ICF-3). All else
17 equal, close proximity to wind resources can facilitate reliable and efficient
18 delivery of such a resource⁶.

⁵ 2,400 MW of wind would produce approximately the same amount of energy as the Sooner and Muskogee coal power plants, though with a different profile and with other characteristics compared with the Sooner and Muskogee output. Hence, ICF conducted a detailed Analysis. See later discussion.

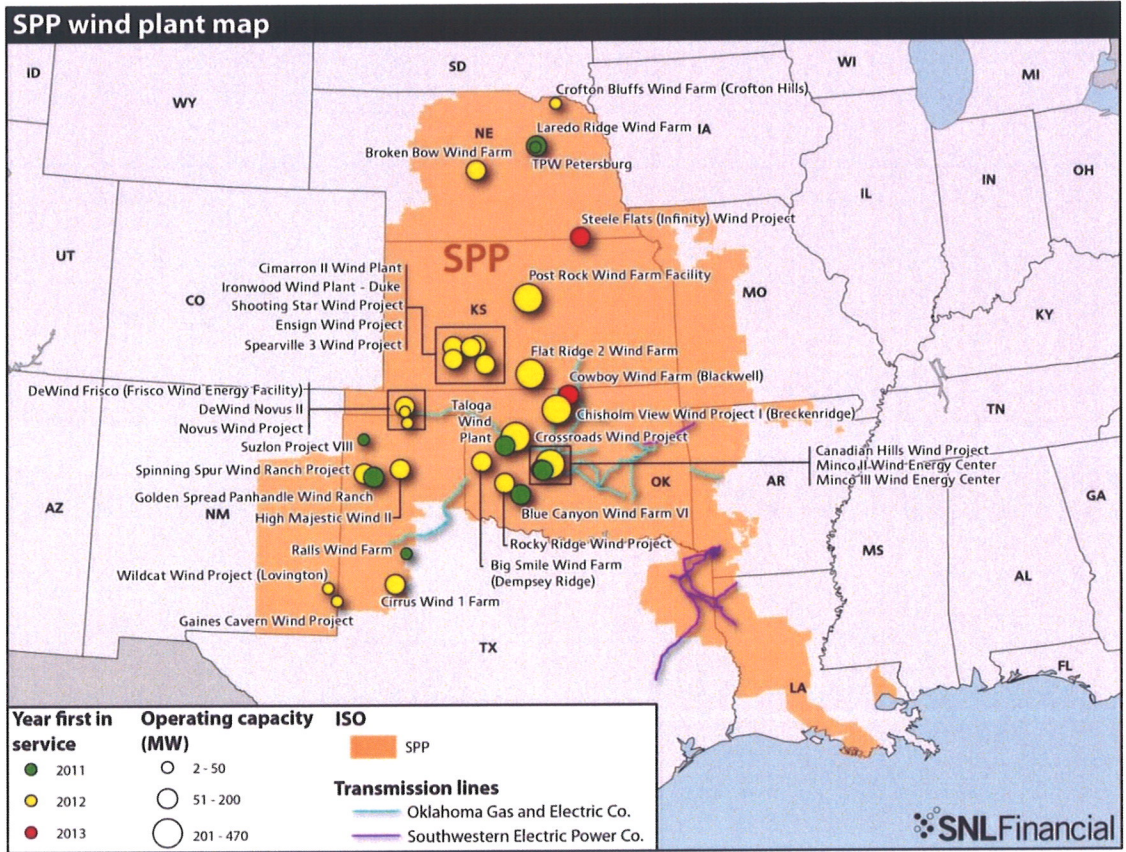
⁶ Here efficiency refers to lower losses. The new SPP electrical energy market, the Integrated Marketplace, uses marginal losses when calculating nodal prices. This creates more discounts for plants distant from load, and premiums for plants close to load, than the EIS construct, all else equal. See later discussion.

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Exhibit ICF-2 Recent Wind Projects in SPP and OGE Footprint

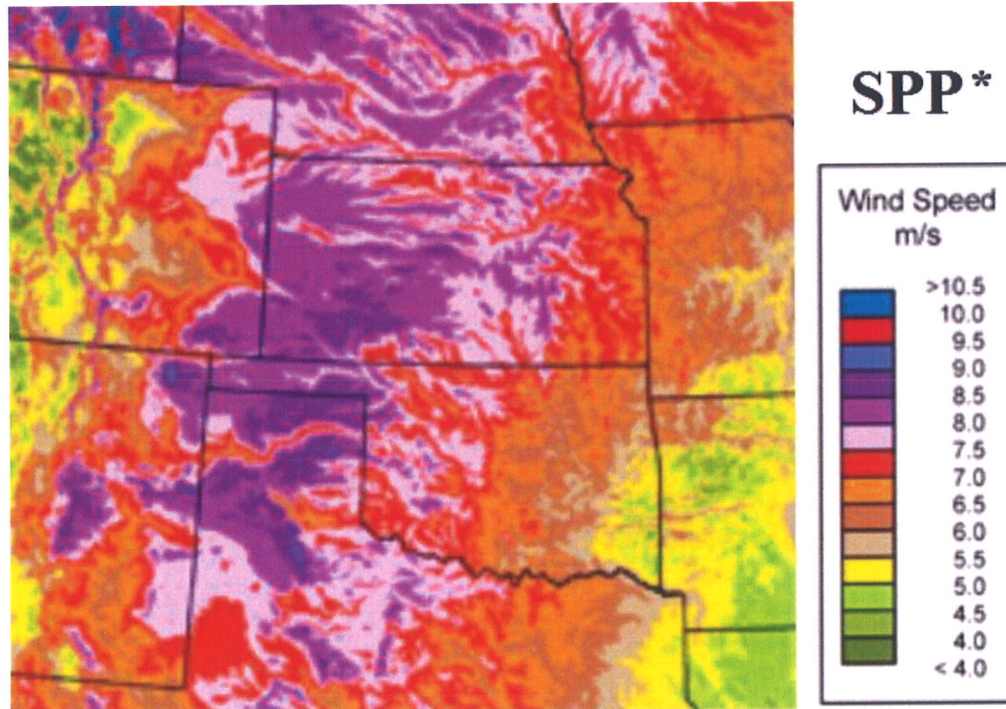


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Source: 1) SNL Financial and ICF International

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Exhibit ICF-3 Wind Resource Potential in SPP at 80m Hub



*Source: http://apps2.eere.energy.gov/wind/windexchange/wind_maps.asp

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■ OGE did not explicitly and quantitatively consider PTC qualified wind as a compliance or modernization option, even in combination with existing or new gas plants which would provide capacity and could firm wind. Rather, OGE, prematurely and without sufficient analysis, screened out the wind and wind/natural gas options. OGE based this decision in part on its theory of transmission risk associated with wind.

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■ OGE did not explicitly and quantitatively consider existing gas plants. Rather, OGE, prematurely and without sufficient analysis, screened out the natural gas options. OGE based this decision in part on its view there was insufficient existing gas power plant capacity, a conclusion reached without an RFP.

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1 ■ The need for detailed transmission analysis is not obviated by OGE’s
2 geographical advantage. The decision not to analyze the wind options and
3 associated transmission issues represents a serious deficiency in OGE’s IRP. An
4 appropriate analysis should include a nodal analysis similar to that undertaken by
5 ICF and other analyses related to the availability of firm transmission. ICF
6 estimates that the discount of nodal prices for PTC qualified wind units in the
7 Integrated Marketplace[1] (“IM”) will be approximately 7 to 8% relative to the
8 zonal average without the Woodward-Tatonga-Matthewson-Cimarron
9 transmission upgrade program currently scheduled for 2021 and approximately
10 3% with the Woodward-Tatonga-Matthewson-Cimarron transmission upgrade
11 program. This discount is factored into our analysis, and furthermore, the benefits,
12 including calculated cost savings, provide significant ability to pay for
13 transmission upgrades if needed to obtain firm transmission service from SPP.
14 Lastly, the SPP IM has introduced marginal losses into its price determination;
15 this was not part of the Energy Imbalance Market (“EIS”) (the previous SPP
16 market construct). Accordingly, many existing generators currently participating
17 in the IM are experiencing discounts regardless of fuel type, not just wind plants.
18 Hence, we do not believe the discounts at nodes with wind plants is an obstacle to
19 moving forward with the PTC qualified wind option.

20 ■ OGE also based its decision to screen out wind options in part on its stated
21 uncertainty about wind options. However, the options OGE considered have
22 similar or larger amounts of uncertainty, and hence, OGE’s exclusion of the wind

1 option results in an analysis that is biased against wind. OGE also based its
2 decision to screen out wind on the lack of capacity contribution from wind. The
3 need for capacity can be addressed by a combination of wind and thermal
4 generation capacity. Natural gas generation in particular represents an attractive
5 potential option.

6 ■ Thermal generation options can provide resource adequacy, capacity, and firming
7 of an intermittent resource like wind so that power can be reliably provided when
8 a customer needs it. Given current and potential environmental developments, the
9 abundance of low-cost natural gas in Oklahoma, extensive natural gas
10 transportation and related storage infrastructure, as well as existing gas fired
11 generation plants in Oklahoma, OGE's wind and PTC qualified wind
12 opportunities have the potential to deliver savings to customers while maintaining
13 high reliability. Gas-fired plants have proven ability to provide firming and load
14 following services, and many are participating today in SPP's ancillary service
15 markets. In reviewing and understanding the Oklahoma market, ICF identified
16 existing gas power plants available to provide firming of wind, and more might be
17 available. This needs to be confirmed with an OGE RFP. There may also be
18 efficient and viable new build or plant expansion options available.

19 ■ Unlike OGE's Base Case, ICF's Base Case analysis accounts for potential CO₂
20 emission regulations which favor wind over coal options, even if all else were
21 equal. On June 2, 2014, the United States EPA proposed regulations on CO₂
22 emission from existing power-plants, generally referred to as the Clean Power

1 Plan (“CPP”) under Section 111d of the Clean Air Act. There is significant
2 uncertainty regarding these proposed regulations. The timing of OGE’s
3 compliance obligations under its Regional Haze regulations means that it must
4 make a decision on SO₂ scrubbers for Sooner and Muskogee before significant
5 additional information about the CO₂ requirements becomes available in the
6 2016-2017 timeframe. Nonetheless, there are reasonable, existing methods for
7 considering CO₂ regulations, and it is important that proper weight be given to
8 their potential impact in the Base Case. Furthermore, the wind and gas options
9 provide a hedge against future tightening of environmental regulations. Indeed,
10 the US EPA bases a portion (the portion referred to as Block 2) of the emission
11 reduction requirements under its recently proposed CPP plan on increased
12 utilization of natural gas fueled combined cycle plants. In the event of federal
13 CO₂ emission regulations, ICF’s modeling conclusions show savings of \$1.0 to
14 \$1.4 billion compared to our modeling of OGE’s IRP Capacity Expansion Plan
15 (Scrub/Convert) course of action with the PTC. The benefit occurs because CO₂
16 regulations raise the electrical energy prices in the IM.

- 17 ■ Expeditious and timely action is required to take advantage of PTC qualified wind
18 facilities. OGE’s RFI for wind in 2013 is not sufficiently up to date. OGE
19 should not go forward until it can demonstrate that PTC qualified wind
20 opportunities have been fully considered, and that OGE has acted to avoid losing
21 available opportunities. OGE should provide sufficient analysis of the energy
22 benefits of the wind opportunities including assessment of congestion,

1 curtailment, and firm transmission service. OGE should conduct market-based
2 solicitations or RFPs for PTC qualified wind and existing natural gas generation
3 capacity to provide back-up capacity for the wind to determine whether a lower
4 cost alternative exists compared to its proposed plan.

- 5 ■ The Mustang “modernization” or repowering also requires an IRP with a
6 complete wind and wind gas assessment. This is because some of the options
7 (Sooner Retrofit or “Scrub” / Muskogee “Convert”) revise a significant portion of
8 the OGE system. The Mustang decision also requires a market test. A market
9 test is important because it may identify lower cost options that could reduce the
10 overall cost of the resulting portfolio to OGE customers. ICF identified

11 [REDACTED]

12 [REDACTED] In reviewing and understanding
13 the Oklahoma market, we believe there may be other options as well, but this
14 cannot be confirmed without an OGE RFP.

15
16 **III. INTRODUCTION TO ISSUES**

17 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

18 **A.** The purpose of my testimony is to review the proposed OGE environmental compliance
19 plan, and OGE’s IRP. In addition, I am reviewing OGE’s proposed modernization plan.

20 **Q. WHY IS THERE A NEED FOR AN ENVIRONMENTAL COMPLIANCE PLAN?**

21 **A.** On May 27, 2014, the United States Supreme Court refused to hear OGE’s objections
22 against EPA’s proposed Regional Haze regulations (See Exhibit ICF-4). The proposed

1 EPA regulation or Federal Implementation Plan (“FIP”) was previously upheld by the
 2 10th Circuit Court of Appeals. The FIP primarily affects SO_x and NO_x emissions at
 3 OGE’s Sooner and Muskogee power plants. With the United States Supreme Court’s
 4 denial of certiorari, OGE exhausted its ability to appeal the FIP which was originally
 5 published on December 28, 2011. As a result, OGE must comply with the FIP by
 6 January 4, 2019 – in approximately five years. Following is a table setting forth a
 7 timeline as to the FIP and the implementation timelines.

8 **Exhibit ICF-4**
 9 **Timeline – Regional Haze and OGE**

Item #	Milestone Id	Compliance Time # of Months	Approximate Date
1	Regional Haze Rule		1999
2	Final Ammendments from EPA		07/06/05
3	OK Submits SIP to EPA For Approval		02/17/10
4	EPA Rejects SO ₂ Portion of OK SIP and Publishes FIP		12/28/11
5	EPA FIP Establishes 60 Month Compliance Period to 0.06 # SO ₂ /MMBtu	60	12/28/16
6	10th Circuit Court of Appeals Upholds EPA FIP	5	06/22/12
7	OG&E and OK Appeal to US Supreme Court, FIP Implementation is Stayed	55	07/01/12
8	US Supreme Court Approval to Hear Case Sought and Denied	23	5/27/2014
9	US Court's Stay Lifted		5/30/2014
10	OGE's New Deadline For EPA FIP Compliance	55	1/4/2019

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12 **Q. ARE THE REGIONAL HAZE REGULATIONS STRINGENT?**

13 Yes. If OGE were to choose to continue to operate the Sooner and Muskogee (Unit 4
 14 and Unit 5) power plants using coal, SO₂ scrubbers would be required.⁷ OGE estimates

⁷ OGE outlines two (2) elements to its planned Regional Haze compliance. First, and by far the most impacting, are SO₂ scrubbers. Also, on P. 11 of his testimony, OGE Witness Howell indicates that OGE plans to install low NO_x burners as required in the Regional Haze SIP. OGE Witness Burch discusses in his testimony the reasoning for OGE’s selection of low NO_x burners as the technology for meeting those requirements at its four Regional Haze-affected coal units and its three Seminole gas-fired steam units. OGE indicates that the installation of the low NO_x burners would be completed by January, 2017 under its plan. Separately, in addition to the SO_x and NO_x requirements of the Regional Haze FIP, OGE plans to take action at its coal-fired plants to comply with EPA’s Mercury and Air Toxics (MATS) requirements. On P.11 of his testimony, OGE Witness Howell states the compliance date for MATS is April 16, 2016, and OGE will have to take action in order to meet that deadline.
 Judah L. Rose Responsive Testimony Cause No. PUD 201400229
 Oklahoma Energy Results, LLC

1 that the cost of scrubbers for the two units at Sooner alone would be \$530 million in
2 total⁸.

3 **Q. WHY IS THE TIMING OF THESE REGULATIONS IMPORTANT?**

4 **A.** The timing of OGE's compliance obligations under its Regional Haze regulations means
5 a decision on OGE's planned SO₂ scrubbers for Sooner and Muskogee would be made
6 before additional information from EPA and other relevant authorities about the CO₂
7 requirements becomes available in the 2016-2017 timeframe.

8 **Q. PLEASE ELABORATE.**

9 **A.** Compliance with regional haze regulations can have significant lead times especially to
10 the extent that the compliance choice involves major capital investment such as SO₂
11 scrubbers. At the same time, on June 2, 2014, the EPA announced proposed new CO₂
12 emission control regulations also affecting existing power plants, including Sooner and
13 Muskogee. These regulations go by the moniker 111d since they are based on Section
14 111(d) of the Clean Air Act. The regulations generally favor non-CO₂ emitting
15 compliance options, such as renewables and lower-emitting options like high efficiency
16 natural gas power plants, as opposed to coal power plants. EPA currently expects to

OGE's plan is to install Activated Carbon Injection ("ACT") on its coal units in order to meet this requirement and allow these units to continue running until the Regional Haze compliance date (and beyond that date if the units remain coal-fired). OGE believes installation of ACT on Muskogee 4 and 5 allows those coal units to remain operational utilizing coal fuel under the MATS requirements. Further, OGE proposes to later convert the Muskogee Units 4 and 5 to natural gas. OGE argues that this approach is a lower cost option for customers than converting or shutting down those units in 2016. OGE Witness Burch discusses the selection of the ACT technology in his testimony. We did not consider in our analysis alternatives to this in part because of the short lead times and low costs of MATS compliance compared to OGE's proposed costs and portfolio amendment for compliance with Regional Haze.

⁸ From a cost perspective, one could purchase approximately 672 MW of wind power-plants after accounting for the PTC. \$550 million/\$818 per kW (after PTC) is 672 MW. The analysis of the alternatives is complex, and involves numerous factors as is discussed later in this testimony.

1 finalize these regulations in June, 2015. Substantial new information is likely to become
2 available about these regulations starting in June 2015, and extending through 2016 and
3 2017. This information includes final regulations, state-by-state filings on
4 implementation currently proposed to be due in 2016 and 2017, and the fate of expected
5 legal and other challenges to the 111d regulations. Thus, all else equal, it would be
6 preferable for OGE to wait until more information becomes available over the next two
7 years to decide on investments and compliance options which are projected to have
8 considerable cost implications to its customers. The desirability of delay
9 notwithstanding, there is a need to analyze options that have long lead times like the
10 retrofit installation of SO₂ scrubbers, as OGE has included some in its IRP.

11 **Q. WHAT SHOULD BE DONE IN THIS REGARD?**

12 **A.** The potential for CO₂ controls should be analyzed even in the Base Case. We therefore
13 propose an approach for accounting for these newly-proposed regulations in the analysis
14 of options, and recommend that expected CO₂ controls be explicitly considered.

15 **Q. DOES THIS APPROACH DIFFER FROM THAT OF OGE?**

16 **A.** Yes. This approach differs from that of OGE which assumes no CO₂ regulations in its
17 Base Case.⁹

18 **Q. WHAT ARE THE KEY ELEMENTS OF OGE'S PROPOSED**
19 **ENVIRONMENTAL COMPLIANCE AND MODERNIZATION PLANS?**

20 **A.** The key OGE recommendations are:

⁹ OGE has a sensitivity case with CO₂ emission costs.
Judah L. Rose Responsive Testimony
Oklahoma Energy Results, LLC

- 1 a. Compliance with regional haze emission regulations at the Sooner coal-fired
2 power plant (1,042 MW) via retrofit of SO₂ scrubbers in 2018 (Sooner 1) and
3 2019 (Sooner 2).
- 4 b. Compliance with regional haze emission regulations at the Muskogee coal-fired
5 power plant (Units 4 and 5 at 1,006 MW total) via conversion to natural gas.
- 6 c. Modernizing via repowering the Mustang site (Units 1-4) from conventional
7 steam natural gas to the use of combustion turbines.
- 8 d. Continuing to pursue energy efficiency.¹⁰

9 **Q. WHAT DOCUMENTS DID YOU REVIEW?**

10 **A.** I reviewed many documents but some of the most important highlight here:

- 11 • The OGE Environmental Compliance plan and resource strategy as described in
12 the testimony of OGE witnesses especially Leon Howell (August 6, 2014), Don
13 Rowlett (August 6, 2014), and Robert Burch (August 6, 2014).
- 14 • The OGE 2014 Integrated Resource Plan (IRP) Update released August 7, 2014.
- 15 • More than 200 additional documents including the application of OGE for
16 approval, testimony of its witnesses, Data Requests (“DRs”), and responses to
17 DRs.

18 **Q. AS PART OF YOUR REVIEW DID YOU ALSO CONDUCT YOUR OWN**
19 **INVESTIGATION INTO THE ECONOMICS OF THE OGE SYSTEM?**

20 **A.** Yes. The details of this analysis are provided in a series of Attachments and the main
21 results are summarized within my testimony.

¹⁰ OGE IRP, page 49.
Judah L. Rose Responsive Testimony
Oklahoma Energy Results, LLC

1 **Q. HOW DID YOU CONDUCT YOUR INVESTIGATION?**

2 **A.** I conducted the investigation using ICF models and databases and other computer
3 simulation programs. This analysis is discussed later in my testimony.

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IV. WIND OPTIONS

6 **Q. WHAT OTHER ALTERNATIVE OPTIONS EXIST TO COMPLY WITH THE**
7 **NEED FOR AN ACCEPTABLE INTEGRATED RESOURCE PLAN AND**
8 **ENVIRONMENTAL REGULATIONS?**

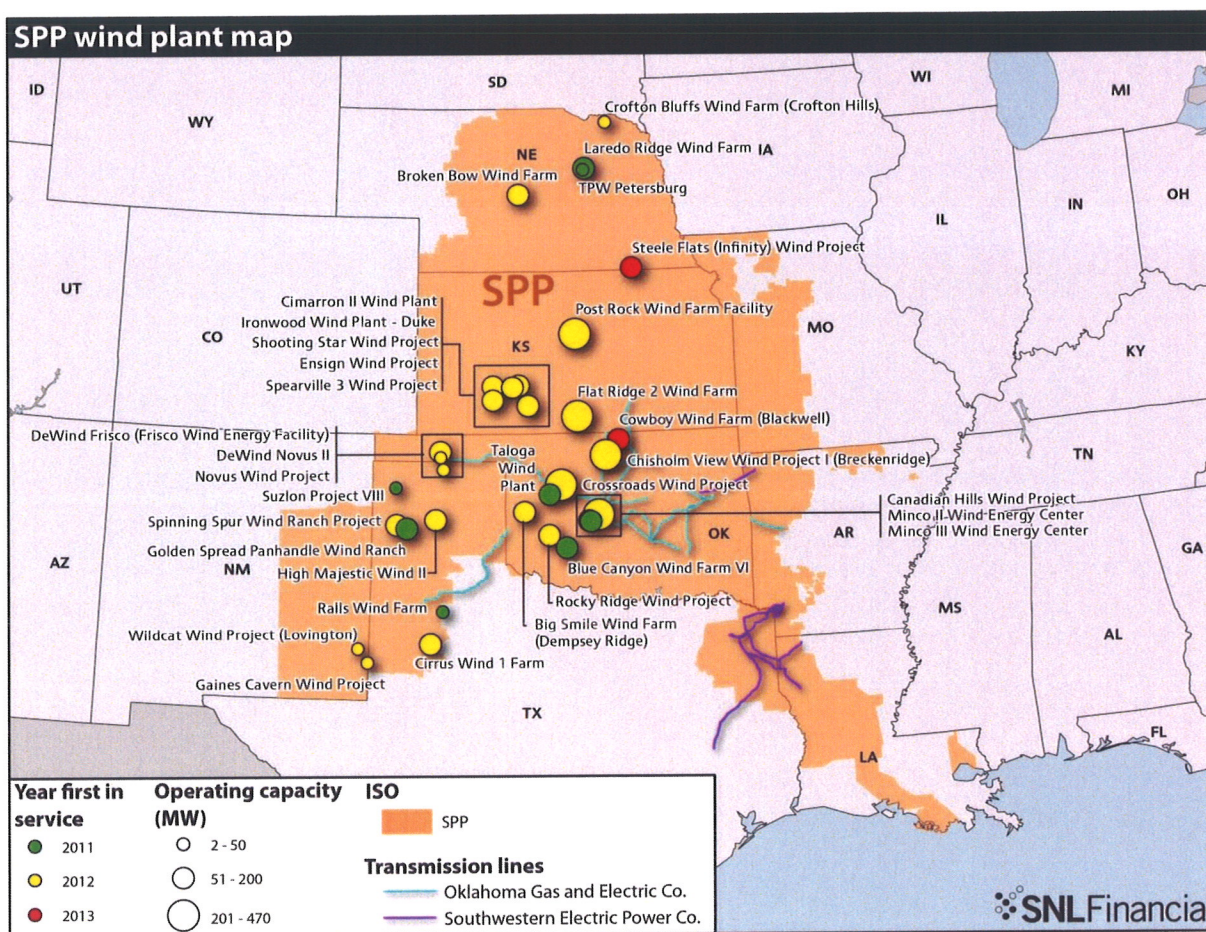
9 **A.** A key alternative resource is the wind power plant option, which is not included in the
10 OGE IRP. There are several features of the wind option that make wind attractive in this
11 instance in particular as a potentially important component of OGE’s plan. These features
12 include anticipated low cost of power due to advances in turbine design, the availability
13 of highly attractive wind resource base, the potential availability of incentives such as the
14 federal PTC, and the close proximity of wind resource to a very large Load Serving
15 Entity (“LSE”) that appear to offer substantive potential to reduce costs to customers if
16 included as a component of OGE’s plan. Specifically:

- 17 • **Location of Wind and OGE** – As of 2013, the service territory of OGE has the
18 largest load in Southwest Power Pool (SPP, see Exhibit ICF-5)¹¹, and closely
19 overlapped with some of the most attractive wind resources in the country. In
20 particular, as shown in the Exhibit ICF-6, the purple shaded area has been
21 identified by the Department of Energy (“DOE”) as having wind resources >8

¹¹ Note that AEP owns both the PSO and SWEPCO utilities; taken together the load requirements of these utilities are larger than those of OGE.

1 meters per second on average.¹² All else equal, close proximity to wind resources
 2 can facilitate reliable delivery. Thus, OGE is ideally situated to utilize advanced
 3 wind turbine technology, and take advantage of very large federal incentives for
 4 the use of wind.

5 **Exhibit ICF-5**
 6 **Recent Wind Projects in SPP and OGE Footprint**

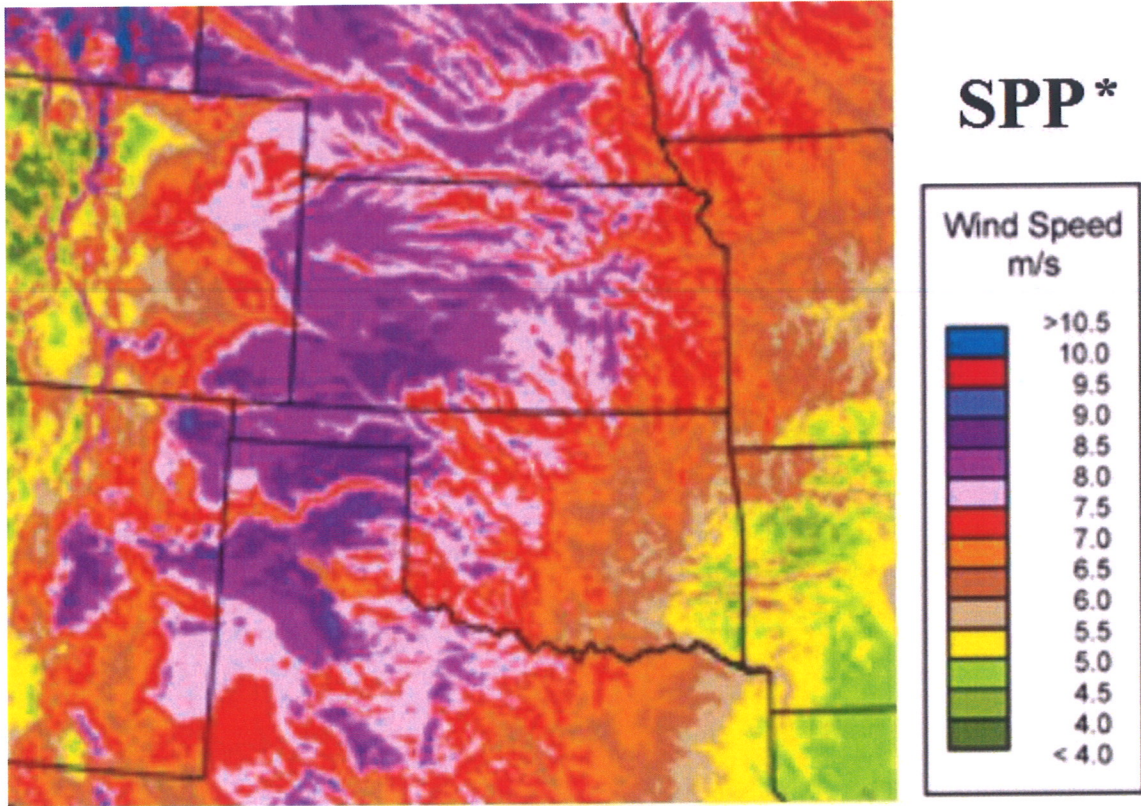


7 **Source:** 1) SNL Financial and ICF International

12 NREL, http://apps2.eere.energy.gov/wind/windexchange/wind_maps.asp, measured at a hub height of 80 meters.

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**Exhibit ICF-6
Wind Resource Potential in SPP at 80m Hub**



*Source: http://apps2.eere.energy.gov/wind/windexchange/wind_maps.asp

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- **Production Tax Credit** – *The full and complete assessment of the availability of PTC qualified wind is critical and OGE needs to complete this assessment before proceeding on its proposed plan. Without this more comprehensive assessment of the capacity and energy contributions of wind, and combinations of wind and gas power plants, an IRP process that requires consideration of least cost criteria is fatally flawed. This is because the federal PTC greatly lowers the costs of electrical energy produced by qualified wind turbines, especially from wind turbines with high capacity factors (e.g. 46% to 49% or higher capacity factors)*

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1 such as those coming on line in central and western Oklahoma. The PTC benefit
2 is approximately \$23/MWh or 2.3 cents per kilowatt hour. Because the incentive
3 is proportional to the MWhs produced, the reduction in the cost per amount of
4 capital investment increases as¹³ the capacity factor increases.¹⁴ The PTC can
5 lower the cost of electrical energy produced by wind turbines up to almost 50%.
6 The availability of nearby PTC qualified wind is highly dynamic. For example,
7 as of the first week in December 2014, it is our understanding that qualified PTC
8 wind projects must either have started construction by January 1, 2014 (Physical
9 Work Test”), or have purchased 5% or more of the total cost of the facility (“Safe
10 Harbor Test”). Furthermore, there must be continuous construction or continuous
11 efforts, and the plant must be on line by January 1, 2016 (i.e. within
12 approximately 2 years from now)¹⁵. Current activity in Congress includes
13 consideration of extension of the PTC, including a proposal that would qualify
14 wind power plants under construction by the end of 2014.¹⁶ Note, even if there is
15 no extension, there can still be PTC qualified wind projects if they meet the
16 provisions described above. Furthermore, unless otherwise stated, the term PTC

¹³ In order to illustrate the impact of the PTC, a 35% capacity factor plant with no PTC costs roughly \$67 (($\$1750/\text{kw} \times 0.1 + 33$) \times (1000/8760 \times 0.35) = \$68). With the PTC, this decreases to approximately \$45/MWh or by 33%. At 50% capacity factor, with no PTC the cost is approximately \$48/MWh. With the PTC, this decreases to approximately \$25/MWh or by 48%. The actual analysis must be performed in a detailed Adjusted Production Cost context, including IM prices. These calculations are shown only to emphasize the importance of capacity factor in wind economics and its magnified importance in the context of the PTC.

¹⁴ DSIRE, http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F. The duration of the credit is generally 10 years after the date the facility is placed in service, although an accelerated schedule may be available.

¹⁵ IRS, Clarification of Notice, 2013-29.

¹⁶ [REDACTED]

1 qualified wind as used in this testimony includes wind currently qualifying or that
2 would soon qualify based on legislation passed in late 2014 or early 2015.

- 3 • **Amount of OGE Wind** – The amount of wind being purchased / owned by OGE
4 is currently 841 MW,¹⁷ which is 11 percent of its 7,656 MW¹⁸ of total resources
5 as of 2014.¹⁹ SPP has 7,142 MW of wind on line as of the end of 2013.²⁰ Also,
6 the state of Oklahoma has 3,114 MW²¹ of wind on line as of end 2013. This
7 supports the view that wind resources are attractive in this region.²²

- 8 • **Wind Generation Technology** – Wind power plant capacity factors have been
9 increasing in recent years, lowering the per KWh cost of wind farm output,
10 especially when accounting for the PTC. As discussed further below, the likely
11 range of capacity factors for recently developed and new wind facilities is 46% to
12 49 % or higher.²³

- 13 • **SPP Transmission Expansion** – SPP has been involved for several years in a
14 major expansion of transmission capacity to accommodate, in part, the
15 development of wind resources. This is especially significant in the case of OGE

¹⁷ This is nameplate capacity.

¹⁸ 6,858 MW of capacity resources plus 841 MW of total wind less 23 MW counting towards reserve margin.

¹⁹ Schedule B – IRP, page 54.

²⁰ SNL Financial.

²¹ SNL Financial, as of 2013.

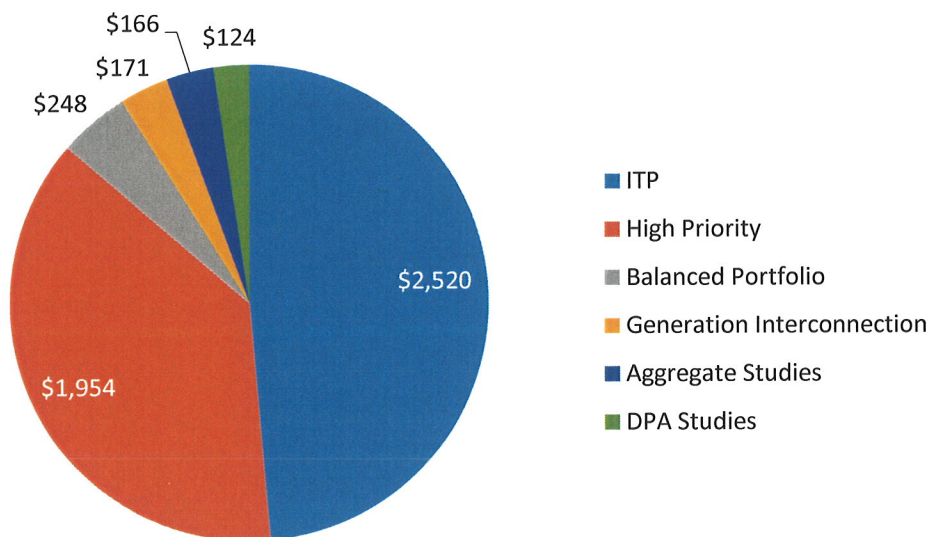
²² We consider scenarios with total wind in SPP of approximately 11,000-12,000 MW. This includes 7,142 MW as of the end of 2013, 1,900 MW of additional that may be available to OGE, and 2,242 MW of new wind builds during 2014-2018 that we consider likely to be built. We refer to this wind build as “firm”. This total build is approximately consistent with the expectations underlying recent SPP transmission plans.

²³ GE, 2014, 1.7 100s are reported by GE to have 53 % gross capacity factors at 7.5 m/s windspeed. http://www.ge-energy.com/products_and_services/products/wind_turbines/ge_1.6_100_1.7_100_wind_turbine.jsp accessed on Dec 5, 2014. Assumptions on expected wind capacity factors are discussed later in this report.

1 given its proximity to wind relative to other utilities.²⁴ Indeed, OGE indicates that
 2 some of its transmission projects have been undertaken to increase the viability of
 3 additional wind projects.²⁵ SPP reports that by the end of 2014, almost \$4.6
 4 Billion USD of transmission projects are expected to have been constructed
 5 within SPP since 2006.

6 **Exhibit ICF-7**

**Committed Projects in Progress:
 July, 2014 - 2021**



7
 8 Source: SPP, UBS Update 112514_v3.pdf (USD in Millions)

9 Between 2006 and the end of 2021, more than \$8.5 Billion USD is expected to be
 10 spent within SPP on major transmission needs, typically for reliability or delivery of
 11 more economic energy including wind. More than 50% of the total 15 year

²⁴ In the OGE 2014 IRP Update, Schedule J (P 60-62) OGE lists Transmission Projects in OGE’s Service Territory representing \$815.1 million USD between 2014 and 2021.

²⁵ P. 11 of OGE Witness Rowlett’s testimony indicates that “...OGE helped open up the northwest part of the state to greater wind development by proposing and construction OGE’s Windspeed transmission line.”

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1 expenditure is expected to be completed by the end of 2014. Between 2015 and
2 2021, slightly more than \$4.0 Billion USD of major transmission projects are
3 expected to be added to the SPP system.

4 An additional perspective on the SPP transmission upgrades comes from the 2014
5 SPP Transmission Expansion Plan report (STEP). The STEP report outlines 386
6 transmission upgrades throughout the SPP region with a total cost of \$6.2 billion
7 dollars. By project type, STEP foresees:

- 8 ■ \$99 million spent for Generation Interconnection projects
- 9 ■ \$86 million spent for Transmission Service projects
- 10 ■ \$535 million spent for Balanced Portfolio projects
- 11 ■ \$1.38 billion spent for High Priority projects
- 12 ■ \$4.13 billion spent for ITP projects

13 These plans are often developed to mitigate transmission issues and risks through
14 these types of investments; however, issues and risks may remain. Detailed
15 discussion regarding this aspect is contained later in this testimony.

- 16 ● **Clean Power Plan (CPP)** – As noted, on June 2, 2014, the US EPA announced
17 the proposed CPP CO₂ control program, which was designed to limit the CO₂
18 emissions of existing power plants. Wind generation does not emit CO₂, and
19 hence, is favored by the proposed plan even if all else was equal. The CPP
20 establishes a statewide limit on CO₂ emissions from existing fossil fuel power
21 plants expressed in lbs. CO₂/MWh by year starting in 2020. Oklahoma's
22 proposed limit in 2030 is approximately 900 lbs/MWh, which is well below the

1 coal emission rate of approximately 2100 lbs/MWh. To the extent that renewable
2 power facilities (including the MWhs from new renewable plants) are included in
3 the state total, the resulting emissions from OGE would be lower, aiding the state
4 in reaching its state limit. With this type of approach, additional wind generation
5 could reduce the State's costs of compliance. This is because with their zero CO₂
6 emission rate, every MWh of renewables decreases the costs of emission
7 reductions at existing fossil power-plants by lowering the average statewide CO₂
8 emission rate. States have flexibility to determine how to comply, including
9 whether or not renewables count toward the limit. However, EPA did use
10 renewables in its Best System of Emission Reductions (BSER) calculation in its
11 modeling of the CPP rule, so there is reason to believe that EPA would approve a
12 state plan that took a similar approach. Specific building blocks of the EPA
13 evaluation process for the CPP used to determine the emission reduction
14 requirements include a focus on re-dispatch to gas which could result in an
15 increase in the capacity factor of combined cycle plants. In Oklahoma, the focus
16 was on re-dispatch of generation that could yield capacity factors as high as 70%
17 for combined cycle natural gas fired plants. Overall, this could be considerably
18 higher than the experience of recent years. Attachment B to this testimony
19 describes some aspects of the CPP in greater detail.

- 20 • **Natural Gas Power Plants** –Natural gas fired assets currently provide resource
21 adequacy and a reduction in CO₂ emissions compared to certain other
22 technologies such as coal. Natural gas-fueled power plants currently complement

1 wind by providing back up and reliability during low wind periods. In the future,
2 should wind generation grow as currently anticipated, the need for wind
3 integration services and grid reliability also grow. Existing SPP gas power plants
4 that can help ensure reliability through the provision of ancillary services can be
5 attractive options in this regard. Additionally, gas plants that can change output
6 rapidly and on short notice can also be valuable enablers for larger quantities and
7 more reliable wind supply. In addition, natural gas power plants provide a hedge
8 against tighter emission regulations. Natural gas fired assets such as combined
9 cycles have lower CO2 emissions compared to certain other technologies such as
10 coal.

- 11 • **Integrated Market** – On March 1, 2014, the SPP initiated a dual settlement (i.e.
12 day ahead and real time) electrical energy market known as the Integrated
13 Marketplace. As noted earlier, this replaces the previous EIS SPP market
14 construct. The IM provides greater visibility and efficiency with respect to grid
15 pricing, operations, and dispatch.²⁶ This facilitates resources with low variable
16 costs (such as wind) to bid and be dispatched, encourages natural gas facilities to
17 effectively participate in ancillary service markets, and should also facilitate
18 integrated treatment of operating reserve requirements to the extent that they are
19 affected by wind, and facilitate transmission planning in light of existing assets,
20 and other future generation resources such as wind..

²⁶ SPP does not have an SPP-operated capacity market. Resource adequacy is the responsibility of each load serving member. SPP also has lead responsibility for transmission planning and eliminating significant and recurring congestion. Also SPP establishes operating reserve requirements at levels that accommodate wind. Lastly, as noted, the IM uses marginal losses. This creates more discounts for plants distant from load, and premiums for plants close to load, than the Energy Imbalance Market (“EIS”) construct, all else equal.

1 Q. HOW MUCH PTC QUALIFIED WIND IS AVAILABLE?
2

3 A. A full and complete assessment of the availability of PTC qualified wind is critical and
4 OGE must complete this assessment before proceeding on its proposed plan. This is
5 because, as noted, to the extent that PTC-qualified wind is available with high capacity
6 factors, the ICF analysis presented later in this testimony indicates wind power is by far
7 the lowest cost source of electrical energy from new power plants, and can do much to
lower costs to customers of electricity supply. [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
13 [REDACTED] There may also be other wind facilities in SPP (outside Oklahoma and the area
14 nearby OGE) that currently qualify for the PTC. In addition, there is active consideration
15 in the US Congress of an extension of the PTC including a proposal that would qualify
16 wind power plants under construction by the end of 2014.³⁰ In light of the potential for
17 changes in the amount of PTC qualified wind, we may update or refine our analysis.

18
19

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

³⁰ As noted earlier, a reference to available PTC qualified wind refers to projects qualified as of early December 2014 or as a result of an extension in the immediate future – e.g. an extension in late 2014 or early 2015 – unless otherwise stated.

Exhibit ICF-8



1
2
3
4
5 **Q. WHY MIGHT ACQUISITION OF WIND REQUIRE EXPEDITIOUS ACTION**
6 **ON THE PART OF OGE?**

7 As of early December 2014, the PTC is only available for wind facilities that began
8 construction by the end of 2013, but this restriction may be lifted if the PTC is renewed
9 in the near future, which is possible as bills including these terms are currently before
10 Congress. To the extent that it is not renewed, or if renewed for a limited period of time,
11 then it is important to contract for available PTC qualified wind, or acquire PTC
12 qualified facilities expeditiously in order to preserve the availability of PTC qualified
13 opportunities.

14 **Q. WHY ELSE MIGHT WIND REQUIRE EXPEDITIOUS ACTION ON THE PART**
15 **OF OGE?**

16 **A.** Transmission service for wind power plants can have a significant lead time depending
17 on the contractual arrangements, type of service requested, and local conditions. For
18 example, a wind facility might be a Non-Dispatchable Variable Energy Resources
19 (NDVER). Thanks to its very low variable cost, an NDVER resource has the ability to

1 submit a very low bid to SPP greatly increasing the probability that it will be dispatched
2 if transmission is available and not curtailed. Firm Point to Point (PTP) or Network
3 Integration Transmission Service (NITS) may be useful for some transactions. Reserving
4 transmission service is done partly through a first-come first-serve process, making
5 timely application very important. In addition, there is lead time for SPP analysis of firm
6 service and for the implementation of any upgrades on the transmission system that SPP
7 might require. Contracting for wind leases (when not already procured) and constructing
8 wind facilities can also involve significant lead times. Lastly, congestion price risk can
9 also be examined and potentially managed using a variety of transmission congestion
10 rights products that are offered or pending in the IM.

11 **Q. DOES OGE INCLUDE WIND AND THE ENERGY VALUE OF WIND IN ITS**
12 **COMPLIANCE OR MODERNIZATION PLANS?**

13 **A.** No.

14 **Q. DOES OGE CONSIDER WIND AND THE ENERGY VALUE OF WIND AS A**
15 **COMPLIANCE OPTION ON ITS OWN OR IN COMBINATION WITH FOSSIL**
16 **RESOURCES?**

17 **A.** No.

18 **Q. IS THIS HIGHLY PROBLEMATIC?**

19 **A.** Yes. The ICF analysis presented later in this testimony shows that some combinations of
20 PTC wind and gas fired power-plants represent a lower cost alternative than the OGE
21 recommendation using the APC metric.

1 **Q. WHAT DOES OGE SAY ABOUT WIND THAT PARTIALLY CORROBORATES**
2 **ICF'S ASSESSMENT?**

3 **A.** On P. 30 of the 2014 IRP update, OGE states:

4 *In 2013, OGE issued a RFI for wind energy. Respondents were encouraged to be*
5 *creative with size and terms of agreements. Responses were received*
6 *from 9 companies that offered 20 locations throughout Oklahoma and Kansas.*
7 *Despite the request, none of the responses were structured such that the suppliers*
8 *took the curtailment risk.....Pricing average approximately \$22/MWh and is*
9 *less than previous RFI's with respondents citing improved technology resulting in*
10 *increased capacity factors and reduction in turbine prices.*

11 In the 2014 IRP Update, on P. 49, OGE indicates that its own:

12 *...analysis indicates that wind energy may provide energy cost savings over a 25*
13 *year period, these savings are dependent on assumed SPP IM prices.*

█ In addition, OGE in █
█
16 █

17 **Q. ARE THESE WIND POWER COSTS SIGNIFICANT TO THIS CASE?**

18 **A.** Yes. The cost information gathered by OGE from its wind RFI and reported in its IRP are
19 very low compared to the upgrades to its own system proposed by OGE in its IRP. Later
20 in this testimony, I will discuss this more fully as part of the ICF analysis section.

³¹ OIEC – 5- 8

³² █

1 Including lower cost alternatives would support the likelihood of attractive economics
2 even after any necessary adjustments are made for transmission issues, and the
3 differences between wind and dispatchable resources – e.g. curtailment and congestion
4 price risks, the time profile of wind power plant output, lower capacity/operating reserve
5 contribution, different locations, and hence, different IM prices at these locations – are
6 taken into account.

7 **Q. ARE ADJUSTMENTS RELATED TO TRANSMISSION ISSUES AN**
8 **IMPORTANT ISSUE?**

9 **A.** Yes. Therefore, some additional discussion of transmission issues related to wind is in
10 order.

11 **Q. WHAT ARE CURTAILMENTS?**

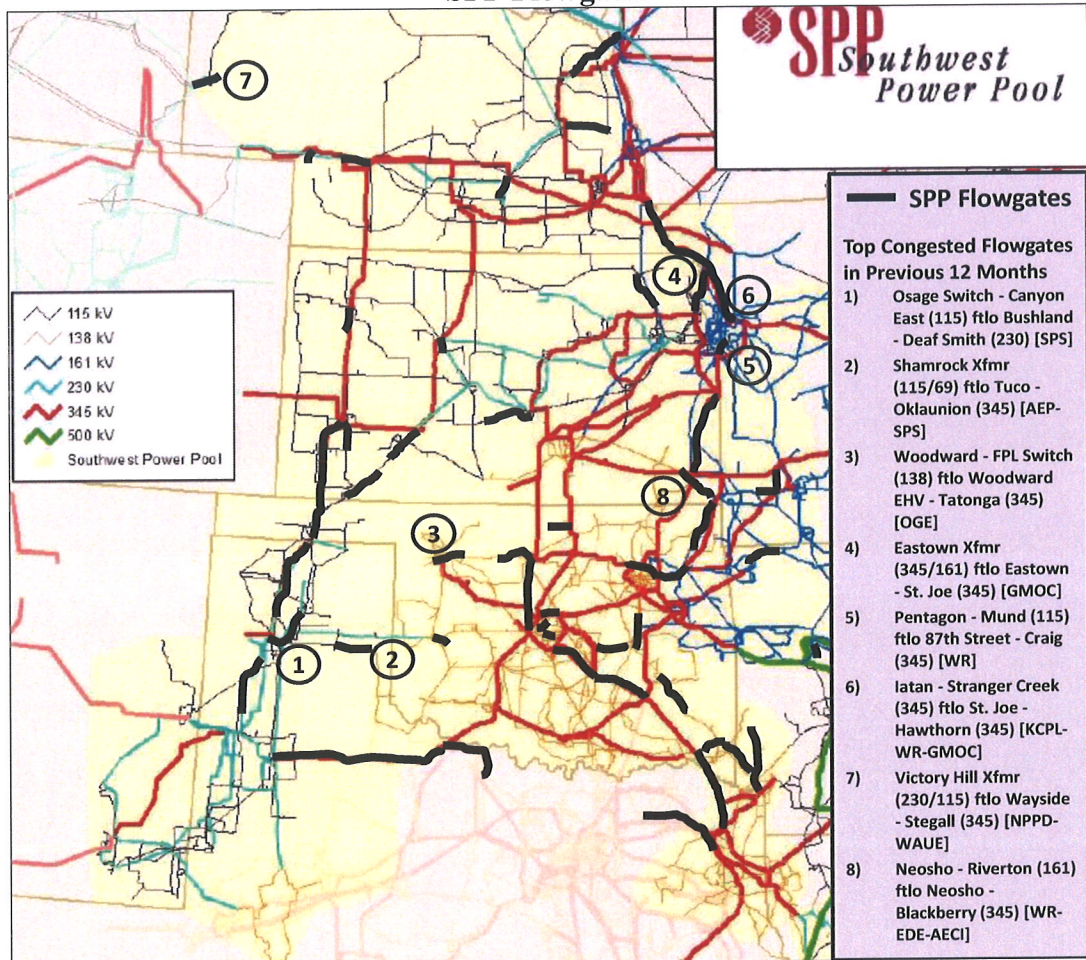
12 **A.** Curtailments are restrictions on the output of a plant due to transmission constraints. The
13 extent of curtailments is primarily a function of congestion on the transmission system,
14 the location of the facility, and the type of transmission service the facility has. For
15 example, a facility with firm PtP transmission service is less likely to be curtailed.
16 Rather, any facility with non-firm transmission service is curtailed first. As discussed
17 previously, many wind facilities which have an intermittent generation profile simply bid
18 into the SPP IM at a very low marginal price to ensure that they are dispatched. Using
19 this commercial arrangement, these wind facilities are subject to curtailment by SPP
20 since they have not identified a sink (load) and paid for firm PtP transmission to it.

21 **Q. WHAT ARE IM CONGESTION RISKS?**

22 **A.** The price of power under the SPP IM has three major components:

1
2

Exhibit ICF-9 SPP Flowgates



3
4

Q. WHY DO YOU HIGHLIGHT THESE TWO FLOWGATES?

5

A. The [REDACTED] are generally located

6

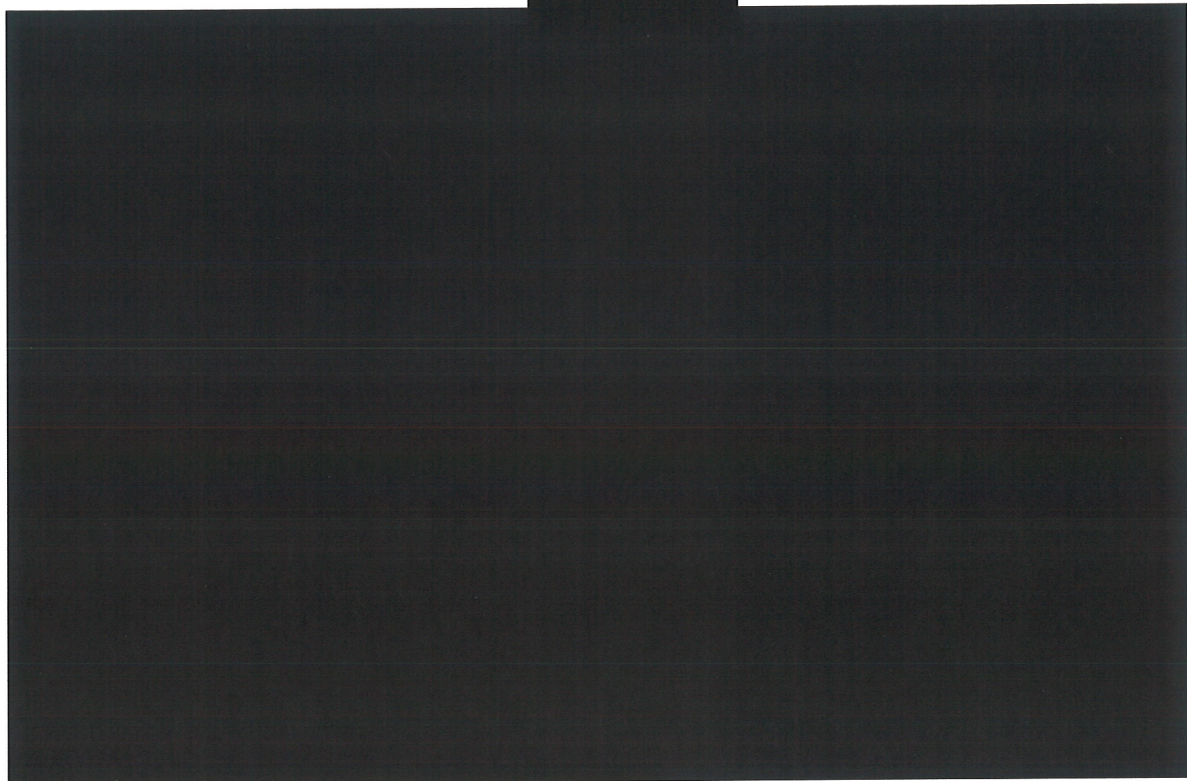
[REDACTED] (see Exhibit ICF-10).

7

8

1
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Exhibit ICF-10

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Q. WHAT ELSE DOES OGE SAY ABOUT WIND OPTIONS?

A. OGE remains concerned with contracting for wind, noting on P. 49 of the IRP:

Based on recent experience with wind energy there is considerable SPP IM price risk and the respondents to our 2013 RFI declined to assume this risk³³. We expect that this price risk will diminish as new transmission capacity is placed in service and will monitor this risk. However, given this risk, OG&E has made a decision not to pursue additional wind generation at this time.

³³ Witness Howell goes on to point out in OIEC 5-8: 



1 OGE also states that it is concerned about SPP curtailments of wind power plant output
2 due to transmission constraints. On P. 48, OGE states:

3 *While analysis indicates that wind energy may provide energy cost savings, these*
4 *savings are dependent on assumed IM prices and wind energy curtailments.*
5 *Based on recent experience, with wind energy there is considerable risk with both*
6 *pricing and curtailments and the respondents to our 2013 RFI declined to assume*
7 *this risk. We expect that IM circumstances will change as new transmission*
8 *capacity is placed in service.*

9 **Q. WHAT ELSE DOES OGE SAY WITH REGARD TO TRANSMISSION**
10 **AVAILABILITY AND WIND?**

11 **A.** In the [REDACTED]

12 [REDACTED] OGE indicates in a section titled [REDACTED] the following:

[REDACTED]
[REDACTED]
[REDACTED]
16 [REDACTED]

17 **Q. WHAT DOES OGE SPECIFICALLY SAY ABOUT WIND CURTAILMENTS?**

18 **A.** [REDACTED] In its analysis of [REDACTED] OGE indicates:

[REDACTED]
[REDACTED]
21 [REDACTED]

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

9 [REDACTED] P. 49 of the 2014 IRP Update

10 summarizes the situation as follows:

11 *This does not imply that wind energy will not continue to serve a critical role in*

12 *OG&E's portfolio and indeed it is likely that OG&E will increase its reliance on*

13 *wind energy over the coming decade, particularly after transmission constraints*

14 *are relieved. The fact is that wind technology and associated capital costs are*

15 *continuing to improve and may indeed reach levels where wind energy tax credits*

16 *are no longer necessary to support growth in wind energy. OG&E will continue*

17 *to monitor the market and revisit its decision as more is understood of the*

18 *uncertainties.*

19 Furthermore, in response to OIEC 2-9, which states: “Provide any analysis conducted by

20 or for OG&E which addresses the estimated maximum level of wind energy which can be

21 reliably and economically used by the OG&E system,” OGE states:

1 *OG&E has not conducted analysis that estimates the maximum level of wind that*
2 *can be reliably or economically used by OG&E in the SPP IM. Both the*
3 *availability (reliability) and pricing (economics) of wind generation, or any type*
4 *of generation resource, are dependent on location in the SPP along with the*
5 *generation mix of the entire SPP (not just OG&E's system). Because of the short*
6 *duration of the SPP IM, the on-going transmission upgrades in western*
7 *Oklahoma and the Texas and Oklahoma panhandle, and the potential for*
8 *significant new wind resources coming on line in the next few years, there is so*
9 *much uncertainty that the company does not believe such an estimate would be*
10 *informative at this time.*

11 Also, in response to OIEC 2-5 which states: “Identify specific transmission constraints
12 that are expected to limit additional OG&E wind energy purchases and provide any
13 economic analysis of the annual total cost of wind energy (\$/MWh) including these
14 constraints” OGE states:

15 *Since the March 2014 implementation of the SPP IM, transmission constraints*
16 *now result in congestion charges. Congestion charges in a constrained area are*
17 *an off-set to the price that generators located in that area are paid for their*
18 *energy output. In some cases, the congestion charges can exceed the offer price*
19 *for the energy, resulting in a negative market price. An example of an unexpected*
20 *transmission constraint that has caused high congestion charges for OG&E's*
21 *wind energy sales into the IM is the flowgate identified as WDFWPLWDWTAT.*

1 *The WDFWPLWDWTAT flowgate represents an overload of the Woodward to FPL*
2 *Switch 138kV line due to an outage of the Woodward EHV to Tatonga 345kV line.*

3 *In addition, the SPP will initiate curtailments of certain generation when parts of*
4 *the transmission system become overloaded in specific circumstances. For*
5 *example, when there is a lot of wind generating in the Woodward area and there*
6 *are lower levels of generation in the Oklahoma City metro area, the Windspeed*
7 *line between Oklahoma City and Woodward could become constrained and lead*
8 *to curtailments of wind in the Woodward area. This constraint (and others on the*
9 *system) depends on the amount of wind energy being generated at any given*
10 *moment and the condition of the transmission system.*

11 *Given that the SPP IM only began operation in March of 2014, OG&E has not*
12 *performed an economic analysis of annual total cost of wind energy including*
13 *these constraints. To perform an economic analysis of the annual total cost of*
14 *wind, OG&E will need data on congestion charges from each season of the year.*

15 **Q. IS THIS UNUSUAL?**

16
17 **A.** Yes. OGE has PROMOD IV and would appear to have the necessary tools to ascertain
18 season by season, and hour by hour congestion charges and address congestion pricing
19 issues via a nodal pricing assessment. While experience with the IM protocol and
20 congestion prices is limited, in other markets congestion prices are often correlated with
21 curtailments. Under the current conditions of uncertainty, our experience is that greater
22 use of simulation tools is warranted to determine a “reasonable range” of congestion

1 prices. Furthermore, other options including significant upgrades to OGE’s units that
2 have significant uncertainty are nonetheless considered. Lastly, there may be
3 mechanisms to limit uncertainty such as firm transmission service, which could have
4 been addressed in related analyses such as an AC load flow contingency analysis. In
5 addition, a thorough investigation of contracting opportunities might reveal contractual
6 terms and conditions that would limit these risks.

7 **Q. WHAT ELSE DOES OGE SPECIFICALLY SAY ABOUT THE NATURE OF**
8 **PRICE RISK RELATED TO WIND PROJECTS?**

9 OGE indicates that it is concerned about price risk related to wind projects. It indicates
10 in OER-5-4 a concern over the outright price risk of accepting the SPP spot market price
11 compared with a long term fixed price it might negotiate. OGE also indicates that the
12 price risk also includes the risk of curtailment due to transmission constraints and
13 congestion charges. It suggests that even for wind farms that it owns, price risks exist if
14 congestion reduces savings for customers. OGE also reports that it has experienced low
15 LMP’s at several of its existing wind facilities due to the congestion component of the
16 LMP. OGE indicates they do not know which transmission constraints are causing
17 congestion, but that that the cause could be one or multiple constraints.

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

21 [REDACTED]

■ [REDACTED]

■ [REDACTED]

■ [REDACTED]

4 [REDACTED]

5 Another perspective about transmission congestion is that in the period March 2014 to
6 August 2014, OGE’s existing wind portfolio experienced a simple average discount
7 compared to the zonal all hours average price of [REDACTED]. Additionally,
8 because SPP has adopted a pricing system which incorporates marginal losses, there are
9 more discounts for generators generally that are distant to load and less discount or even
10 premiums for plants close to load compared to the previous EIS market construct. Thus,
11 other non-wind plants, including existing gas and coal generation, can also have
12 discounts.

13 **Q. WHAT MORE DOES OGE SAY ABOUT THE WIND OPTION?**

14 A. Furthermore, in DR responses and on P. 18 of his testimony, OGE Witness Howell
15 indicates that:

16 *Although the focus of this IRP is the environmental compliance plan, we still need to*
17 *provide the model with resources that would keep OG&E in compliance with SPP*
18 *capacity margin requirements. While the actions taken to achieve the 2020 goal*
19 *allows OG&E to defer new incremental generation until the year 2020, the retirement*
20 *of the Mustang generating units requires OG&E to begin replacing the capacity by*

1 2018. To that end, we evaluated the following three expansion options for these
 2 purposes as shown in Chart 2 (Exhibit ICF-11):

3 **Exhibit ICF-11**

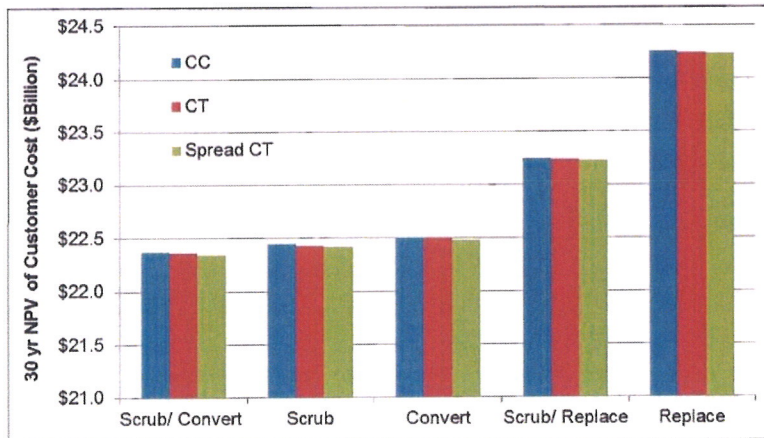
4 **Chart 2**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2031
CC	560 MW CC						560 MW CC		560 MW CC				560 MW CC
CT	400 MW CTs		560 MW CC				560 MW CC					560 MW CC	
Spread CT	280 MW CTs	120 MW CTs	560 MW CC				560 MW CC					560 MW CC	

5
 6 After presenting these three expansion options in the IRP, Witness Howell goes on to
 7 suggest that these expansion options have no material impact on the selection of the
 8 environmental compliance plan. Further, he suggests that the expansion options had very
 9 little impact on the evaluation of the cost of the environmental compliance alternatives
 10 since there is very little difference in NPVCC among the three expansion plans when they
 11 are included with each of the five environmental compliance plan portfolios.

12 **Exhibit ICF-12**

Chart 3



1 However, since the IRP did not consider low cost wind or existing combined cycle gas
2 PPA purchases as a part of OGE's portfolio, it is possible that a focus on capacity-only
3 (or capacity-first) led OGE to overlook combinations of assets that would have met the
4 capacity needs of OGE for planning purposes and held the possibility to reduce costs
5 below the Scrub/Convert option. In our ICF Analysis, presented later in this testimony,
6 we consider these combinations explicitly since low cost alternatives are an important
7 part of any IRP process. In fact, Witness Howell indicates on P.21 of his testimony that
8 wind resources were considered as a solution to Regional Haze and MATS and goes on
9 to say:

10 *However, wind generation does not serve as an effective resource to address the*
11 *planning capacity needs in OG&E's environmental compliance plan. Wind energy*
12 *has a very low capacity value under SPP rules. SPP only allows OG&E to count*
13 *approximately 5% of the nameplate capacity towards its planning capacity margin*
14 *requirements. If OG&E retires one 500 MW coal unit, we would need to install*
15 *approximately 10,000 MW of nameplate wind capacity to satisfy the SPP planning*
16 *capacity margin requirements.*

17 The 2014 IRP Update pp. 47-48 stated the OGE position in another way:

18 *OG&E considered including wind generation as an element of the environmental*
19 *compliance plan analysis but determined that it would not add any incremental*
20 *insights that would affect the analysis or recommendation. The primary consideration*
21 *is the absolute requirement that OG&E replace the capacity provided by the existing*

1 coal units with a like amount of capacity in order to meet its load obligations. SPP
2 only recognizes approximately 5% of nameplate wind generation capacity for
3 capacity margin purposes, implying that 10,000 MW of wind would be needed to
4 replace just one of OG&E's 500 MW coal units. In addition, wind generation serves
5 little purpose in complementing the coal units, as once modified with environmental
6 compliance technology (i.e., the dry scrubbers), wind generation will not reduce the
7 emissions rates of these units. OG&E's coal units will resume dispatch at a high
8 capacity factor within the SPP market.

9 This does not imply that wind energy will not continue to serve a critical role in
10 OG&E's portfolio and indeed it is likely that OG&E will increase its reliance on
11 wind energy over the coming decade, particularly after transmission constraints are
12 addressed over the next two years.(emphasis added) The fact is that wind technology
13 and associated capital costs are continuing to improve and may indeed reach levels
14 where wind energy tax credits are no longer necessary to support growth in wind
15 energy. Here as in previous IRP's, wind generation is evaluated based on customer
16 savings.”

17 Left unstated by OGE is whether a combination of PTC qualified wind and capacity
18 (acquired through purchases from existing natural gas generation, an asset acquisition, or
19 an alternate combination) might result in a lower cost than the selected OGE Scrub /
20 Convert option. Furthermore, the impact of the SPP addressing over the next two years
21 transmission constraints (see above underlined quote) can be modeled using tools that

1 incorporate nodal pricing. This is what ICF has undertaken in its analysis. OGE should
2 consider something similar.

3 **Q. HAS OGE SYSTEMATICALLY ESTABLISHED THE AVAILABILITY OF**
4 **FIRM TRANSMISSION SERVICE AND ASSOCIATED COSTS FOR WIND**
5 **PROJECTS THAT RESPONDED TO THE 2013 OGE RFI OR FOR OTHER**
6 **WIND PROJECTS IN SPP?**

7 **A.** No.³⁵ When asked:

8 *What transmission upgrades are likely to be necessary for OGE to facilitate firm PTP*
9 *or NITS service for new wind or natural gas facilities?*

10 OGE responded:

11 *SPP will determine the details such as types of transmission improvements, timing of*
12 *improvements, and costs associated with improvements. Furthermore, the specific*
13 *transmission facilities, and the costs of those facilities depend on the location of the*
14 *generation installed, the location of the load purchasing the generation, and the size*
15 *of the generation.*

16 **Q. HAS OGE CONDUCTED AN RFI OR RFP OR INITIATED WIND STUDIES**
17 **SINCE 2013?**

18 **A.** No. OGE indicates it will reexamine wind options in 2015.³⁶ Further, on P.29 of his
19 testimony, OGE Witness Reed indicates the following as to OGE's decision to consider
20 wind options at this time.

³⁵ OER 4-4, December 4, 2014.

³⁶ 2014 IRP Update pp. 47-48

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1 *The decision to take a pause on OG&E's aggressive wind energy additions for a*
2 *year or two seems reasonable at this time given the uncertainties associated with*
3 *the relatively new SPP wholesale market and the impacts of transmission*
4 *congestion on those prices. In addition, there is considerable uncertainty*
5 *regarding the future of tax credits for these units and their impact on locational*
6 *marginal prices in the SPP IM. Finally, given the very small capacity credit that*
7 *wind provides, these resources cannot play a significant role in meeting OG&E's*
8 *need to address the Regional Haze FIP. OG&E has indicated that it will issue a*
9 *Request for Information ("RFI") to gather market information with respect to*
10 *wind, energy and fossil fuel generation to inform the preparation of its 2015 IRP.*

11 **Q. SHOULD OGE HAVE DONE MORE REGARDING THE WIND OPTION?**

12 **A.** Yes. A proactive approach to wind is an important element of planning in the case of
13 OGE as the ICF Analysis of its system demonstrates. This is because of the potentially
14 large savings to customers from wind and the protection wind provides against even
15 tighter environmental regulations than those modeled by ICF. This proactive and
16 particularly appropriate approach given the changing environmental regulations would
17 fully assess PTC qualified wind availability and transmission aspects of wind
18 procurement.

19 **Q. DOES YOUR ANALYSIS INCORPORATE TRANSMISSION CONGESTION**
20 **EFFECTS?**

21 **A.** Yes. ICF estimates that the discount of nodal prices for PTC qualified wind units in the
22 Integrated Marketplace[1] ("IM") will be approximately 7 to 8% relative to the zonal

1 average without the Woodward-Tatonga-Matthewson-Cimarron transmission upgrade
2 program currently scheduled for 2021 and approximately 3% with the Woodward-
3 Tatonga-Matthewson-Cimarron transmission upgrade program. This discount is factored
4 into our analysis, and furthermore, the benefits and potential cost savings if OGE were to
5 instead add substantial amounts of PTC qualified wind, and existing natural gas capacity,
6 provide significant ability to pay for the cost of transmission upgrades, to the extent
7 needed, to obtain firm transmission service from SPP.

8 V. SYSTEM PLANNING CONSIDERATIONS

9 **Q. OGE'S IRP ANALYZES UTILITY SYSTEM UPGRADES AND**
10 **MODERNIZATION RESOURCE COMBINATIONS AND MAKES**
11 **RECOMMENDATIONS REGARDING SUGGESTED SYSTEM ASSET**
12 **CHANGES. ARE WIND-BASED POWER PLANTS AND ADEQUATE**
13 **TRANSMISSION THE ONLY ADDITIONS WORTHY OF CONSIDERATION?**

14 **A.** No. While wind plants would provide many advantages, system planning typically
15 considers additional factors. For example, wind power plant capacity does not
16 significantly count toward meeting planning reserve margin requirements (only
17 approximately 5% of wind capacity counts towards capacity planning margin³⁷). As a
18 result, it is common to consider other types of generating assets such as natural gas-fired,
19 coal, nuclear, and hydro. Resources like these can contribute materially to meeting a
20 specified reserve margin while providing energy at a reasonable cost.

³⁷ On Page 11 of OGE Witness Rowlett's testimony, he indicates "...wind does not serve as an effective resource to address the replacement capacity needs in GE's environmental compliance plan. ...If OGE retires one 500 mw coal unit, we would need to install approximately 10,000 MW of nameplate wind capacity to satisfy the SPP planning capacity margin requirement. OGE is still very interested in wind. With 841 MW of wind generation in its portfolio, OGE has always been a strong advocate for wind energy. In fact, OGE helped open up the northwest part of the state to greater wind development by proposing and construction OGE's Windspeed transmission line. OGE is still trying to understand i) how wind affects SPP market prices, and vice versa; and ii) whether additional transmission will remedy congestion issues near wind energy rich areas in the SPP that have been experiencing SPP market price volatility."

1 **Q. IN ADDITION TO MEETING CAPACITY OR OPERATING RESERVE**
2 **REQUIREMENTS FOR RESOURCE ADEQUACY, WHAT OTHER TYPES OF**
3 **FACTORS SHOULD BE CONSIDERED?**

4 **A.** System reliability, cost certainty, price volatility, and the ability to provide ancillary
5 services are factors that are commonly considered by system planners. System reliability
6 typically involves considering the fuel supply, generation, and transmission system as a
7 whole to consider combinations that increase the likelihood that the system can meet the
8 amount a particular customer needs at a particular moment in time. Cost certainty
9 typically focuses on providing power at a known price to the customer. Price volatility
10 can be introduced due to temporary scarcity or surplus of power or fuel. Ancillary
11 services are wholesale market products that compensate a generator for performing a
12 number of operations that maintain system reliability. These products can include things
13 like modifying plant output up or down in response to customer changes in load. Some
14 technologies perform this function better than others. One measure that is typically
15 referred to is known as a unit's ramp rate. Under the IM, SPP has created several new
16 categories of ancillary service products designed to compensate generators for providing
17 this type of service. Other ancillary service products compensate providers for services
18 such as being available to assist in restarting the grid after a catastrophic failure (black
19 start) or varying output over a very short time horizon (e.g. spinning reserve, responsive
20 reserve) as well as reactive power and voltage support. Some of these services can be
21 provided using market-based bidding; others are typically administratively determined.

1 **Q. WHAT OTHER MATTERS DOES A SYSTEM PLANNER CONSIDER?**

2 **A.** A system planner typically considers many things including a mix of generating
3 technologies and fuel sources in an asset portfolio. This is partially due to past decisions,
4 partly the result of existing technology choices and costs, and partly the result of
5 available fuels and costs. Typically, the system planner screens a number of alternatives
6 in an attempt to identify a least cost portfolio that meets multiple objectives. Finally, a
7 system planner typically considers how the generation output will be delivered to the load
8 (or sink). This can also involve numerous discussions and inquiries with the regional
9 transmission operator (SPP) to examine if firm point-to-point transmission (Firm PtP)
10 service is available.

11
12

VI. NATURAL GAS GENERATION

13 **Q. THE OGE IRP APPEARS TO ANALYZE MANY RESOURCE COMBINATIONS.**
14 **ARE YOU SUGGESTING WIND-BASED POWER PLANTS AND ADEQUATE**
15 **TRANSMISSION THE ONLY ADDITIONS WORTHY OF CONSIDERATION?**

16 **A.** No. In Oklahoma, extensive and existing reserves of natural gas have meant that
17 numerous natural gas power plants have been developed in recent decades. As discussed
18 previously, numerous coal-fired plants, as well as other technologies, have also been
19 developed. Wind is but one choice of several alternatives.

20 **Q. WHAT ARE THE ADVANTAGES OF NATURAL GAS AS A FUEL FOR**
21 **POWER PLANTS?**

22 **A.** In recent decades, extensive gas reserves at very competitive prices have been located in
23 Oklahoma and nearby states. Some of these reserve additions are utilizing new cost-
24 effective technology to extract natural gas from shale previously considered relatively

1 impermeable. As a result, gas supply has increased and costs have declined since the
2 2007-2008 period as these new reserves have come on-line. Thus, in areas like
3 Oklahoma, gas-fired generation has continued to be attractive. Additionally, numerous
4 gas pipelines and storage assets exist in Oklahoma and the region. Properly designed
5 asset portfolios can benefit from this extensive supply infrastructure and facilitate more
6 reliable operation.

7 **Q. WHAT NATURAL GAS ALTERNATIVES EXIST TO COMPLY WITH ENVIRONMENTAL REGULATIONS AND/OR MODERNIZE THE FLEET?**
8

9 **A.** The gas-fired alternatives include:

- 10 • New peaking units – combustion turbine simple cycle – CT frame.
- 11 • New peaking units – combustion turbine simple cycle – CT aero-derivative.
- 12 • New combined cycles (CC).
- 13 • Existing Gas power plants – combined cycles, cogeneration.
- 14 • Coal-fired steam conventional boiler to gas conversion.
- 15 • Cogeneration

16 **Q. DO THE CHARACTERISTICS OF GAS PLANTS VARY SIGNIFICANTLY?**

17 **A.** Yes. Performance can vary significantly on a variety of metrics including:

- 18 • Cost
- 19 • Thermal efficiency
- 20 • Operational flexibility
- 21 • Non-fuel costs

- Fuel delivery costs

Q. WHAT ARE THE ADVANTAGES OF NATURAL GAS POWER PLANTS?

A. Compared with coal-fired plants, gas fired plants generally have fewer air emissions even for conventional coal-fired boilers that are converted to natural gas. These conversions of conventional boilers, along with older CT's, tend to have the poorer heat rates and lower conversion efficiencies. Gas-fired technologies generally share the following benefits:

- Substantially higher contribution to capacity planning requirements imposed by SPP when compared with wind.
- Have the ability to sell into the ancillary service markets of SPP while wind does not.
- Have the ability to offset the intermittent nature of wind generation. Compared with other fossil assets such as those that are coal-fired, gas-fired assets can generally support faster output change needs (e.g. ramping, operating or spinning reserve), and come on-line more quickly.
- Lower SOx and NOx emissions than coal-fired plants.
- Some newer gas technology configurations (typically most existing and new CC's, cogeneration, as well as newer CT's) emit less CO2 per unit of output than from coal-fired boilers. This can reduce CO2 per unit of output by up to 45% depending on configuration.

1 **Q. HOW CAN GAS FIRED GENERATION CONTRIBUTE TO RESOURCE**
2 **ADEQUACY?**

3 **A.** Resource adequacy (i.e. meeting the SPP planning reserve margin of 13.6% or capacity
4 reserve margin of 12%)³⁸ is an important issue as OGE analyzes its options, because
5 additional generation capacity counting toward the reserve margin is required if coal
6 power plant capacity is to be replaced. An attractive alternative is to combine natural
7 gas fired and PTC qualified wind power plants into a resource portfolio alternative with
8 low energy costs while maintaining capacity at levels designed to meet the reserve
9 margin requirements.

10 **Q. WHAT IS OGE PROPOSING REGARDING GAS-FUELED GENERATION?**

11 **A.** In their IRP, OGE is proposing to convert Muskogee Units 4 and 5 from coal to natural
12 gas, and repowering the Mustang Power Plant (Units 1 through 4) from conventional gas
13 steam technology to combustion turbines – i.e. building new units.

14 **Q. CAN YOU PROVIDE MORE DETAIL REGARDING THESE PROPOSED**
15 **CHANGES?**

16 **A.** The Muskogee power plant (Units 4 and 5) currently consists of two conventional coal-
17 fired steam units. After conversion to natural gas, the Muskogee units would be very
18 likely to have much poorer thermal efficiency than a combined cycle or cogeneration
19 power plant. While originally constructed as a coal-fired plant, the Muskogee heat rate
20 after conversion is [REDACTED] which is
21 considerably higher (and therefore requires more fuel input per MWh of output) than that

³⁸ Reserve Margin = (Capacity – Demand)/Demand. Capacity Margin = (Capacity – Demand)/Capacity. The two measures are related thus Reserve Margin = Capacity Margin/(1 – Capacity Margin) = 12%/(1 – 12%) = 13.6%.

1 of an existing combined cycle plant. New combined cycle units can be expected to
2 operate with a steady state, full load heat rate of approximately 6,800 Btu/kWh. Even a
3 ten-year old combined cycle plant might have a steady state, full load heat rate of
4 approximately 7,100 Btu/kWh. This means that an existing combined cycle plant would
5 require approximately [REDACTED] less fuel to produce the same
6 MWh of energy output when operated at a steady state, near full load. It would also
7 produce perhaps [REDACTED] less CO2 per MWh than the
8 converted Muskogee unit. The Muskogee power plant, even if converted, is also
9 relatively inflexible in its operation because it is a conventional steam unit. It can require
10 12 or more hours per start (cold start) for this type of unit to come on line versus 10
11 minutes to 2 hours for some of the other gas power plant choices. This type of unit also
12 has a ramp rate of perhaps 6 MW a minute. Hence, a conventional gas-fired steam unit
13 can have decreased economic attractiveness compared to other more flexible gas plants,
14 all else equal.⁴⁰ As a result, it is likely to be much less frequently dispatched in an
15 organized market like the IM. However, it appears to be a low capital cost option.⁴¹ This
16 needs to be balanced against other factors such as a high heat rate (that could limit a
17 conventional steam unit's ability be economically dispatched frequently) compared to
18 newer CC and CT options, and its relatively inflexibility to provide ancillary services
19 compared to newer CC and CT options.

⁴⁰ New combined cycles have faster ramp times.

⁴¹ \$35.7/kW capital cost for the Muskogee conversion – see page 28 of OGE's IRP [REDACTED]

1 The Mustang modernization is essentially proposed as a repowering from conventional
2 boiler units to gas turbines. While simple cycle CT's provide substantial flexibility and
3 are able to ramp their output up and down output quickly, the OGE recommendation is
4 also a high capital cost option and less efficient from a fuel burn perspective than a
5 combined cycle⁴². Operationally, the proposed replacement units can be expected to start
6 quickly in response to changing supply and demand conditions. They also are likely to
7 have the ability to sell products into the SPP Ancillary Service markets.

8 **Q. DO YOU HAVE ANY CONCERNS REGARDING THESE OGE PROPOSED**
9 **CHANGES AT MUSTANG?**

10 **A.** Yes. While OGE has proposed an investment program to install the Mustang capacity and
11 cites transmission and permit benefits for its siting choice, it is less clear how the
12 alternative will benefit the OGE system and its customers as a whole. Additional work
13 by OGE to quantify the units expected contribution to and revenue benefits from the SPP
14 Ancillary Service markets would be a solid first step as OGE has not included this
15 analysis in its IRP process. Additionally, if the units are needed at this location for
16 voltage support, sub-regional reliability, or to meet dynamically changing load or
17 generation profiles, these studies would be a solid second step as OGE has not included
18 this analysis in the IRP process. Finally, if the Mustang modernization could be shown
19 to relax transmission import limits and increase PTC qualified wind takes into the LSE
20 area, these would be substantial additional benefits that might help to justify selection of
21 this high capital cost alternative. OGE does not present evidence in its IRP process that it
22 has considered this factor.

⁴² IRP page 31, overnight capital costs of \$1002/kW in 2014\$.
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VII. EXISTING NATURAL GAS POWER PLANTS

Q. WHAT ARE THE ADVANTAGES OF EXISTING SPP GAS POWER PLANTS?

A. Existing SPP natural gas power plants have the advantage of known and measurable capacity that is already sited, permitted, constructed, and in place. This reduces or eliminates certain risks and uncertainties such as construction costs, the ability to obtain permits, and new transmission constraints. This type of resource typically does not require lead time to develop, so a change in contracting or ownership can count significantly toward meeting planning reserve margin requirements within a known and often expedited timeframe. Resource adequacy (i.e. meeting the SPP planning reserve margin of 13.6% or capacity margin of 12%) is an important issue as OGE analyzes its options, because additional generation capacity counting toward the reserve margin is required if coal power plant capacity is to be replaced. Acquiring the output or existing gas-fired assets directly hold substantial potential to measurably and quickly assist in meeting OGE’s capacity needs.

Q. WHAT IS YOUR CONCERN REGARDING OGE’S PLANNING AND CONSIDERATION OF EXISTING GAS POWER PLANTS?

A. OGE has not given adequate consideration to its gas options, especially existing gas power plant options that may currently be owned by others. OGE states:⁴³

OGE has acquired two existing combined cycles in the past (McClain and Redbud). However, it should also be noted that our analysis indicates that the

⁴³ See IRP page 47.
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acquisition cost of this alternative would have to be very aggressive in order to compete with the “Convert” alternative, less than \$250/kW for a highly efficient plant.

Q. HAS OGE CONDUCTED A RECENT RFP FOR EXISTING GAS POWER PLANT SUPPLY?

A. No.

Q. HAS OGE GIVEN ADEQUATE CONSIDERATION TO EXISTING NATURAL GAS POWER PLANT OPTIONS?

No. On P. 28, the IRP states that “OGE also determined that no CT’s are available for acquisition in the region...” OGE indicates that it came to this conclusion in the spring of 2014 based on OGE’s experience in the SPP marketplace and its general knowledge of what generation resources were available at that time. OGE

[REDACTED]

[REDACTED]

2

[Redacted]

[Redacted]

3

4

[Redacted]

5

Q. HAS OG&E ANALYZED EXISTING COMBINED CYCLE OPTIONS ALONE OR TOGETHER WITH WIND?

6

7

A. No.

8

Q. IS THE LACK OF EXISTING GAS POWER PLANT AND EXISTING GAS/WIND PORTFOLIO ANALYSIS AN IMPORTANT ISSUE?

9

10

A. Yes. In the past, OGE has met at least part of its needs by purchasing existing power plants at discounts to new unit costs. Furthermore, it is important to determine the

11

1 availability of gas plants in light of the potential attractiveness of PTC qualified wind.
2 Lastly, our ICF analysis which follows shows natural gas capacity and PTC qualified
3 wind to be a “superior” option based on potential customer saving and wind and natural
4 gas capacity availability.

5 **Q. WHAT ISSUES AND RECOMMENDATIONS DO YOU HAVE WITH RESPECT**
6 **TO THE MUSTANG MODERNIZATION PORTION OF THE IRP**
7 **SPECIFICALLY?**

8 **A.** It is not apparent that OGE performed a market test for gas fired capacity, either CT or
9 combined cycle (“CC”). OGE’s IRP indicates that such blocks will be important in the
10 2018-2022 future period. OGE Witness Burch maintains that Mustang, as currently
11 configured, is technically obsolete, and OGE mentions concerns with the units’ cycling
12 operation. These represent valid considerations; however, the sizing of Mustang as
13 CT/peaking capacity could depend in part upon what other assets are available for
14 purchase, contracting in the market, and the additional imports of intermittent resources.
15 OGE should have considered the role of the Mustang asset in light of existing regional
16 resource availability for contracting or purchase. It is possible that such a market test
17 would have uncovered potential assets, just as ICF did during the course of its analysis.
18 When gas-fired assets are combined with other categories of market assets, such as wind,
19 and with the relevant environmental compliance options contemplated, a more informed
20 choice may have potentially resulted in a lower cost portfolio than the one suggested by
21 OGE under its IRP and in its Application.

1 **A. WHY IS THE LACK OF AN OGE RFP PARTICULARLY PROBLEMATIC IN**
2 **THIS CASE?**

3 The lack of a RFP is particularly problematic in light of the fact that near the OGE LSE
4 and within SPP there are uncommitted existing merchant natural gas power plants. New
5 construction makes more sense in regions where the system as a whole is capacity
6 deficient, all else equal. Merchant plants offer the following potential additional
7 advantages.

- 8 • Owner's Costs – Some of the existing combined cycles may be available without owner's
9 costs which are associated with start up, and a variety of other costs including
10 management of the project which are not applicable to existing plants.
- 11 • AFUDC - There is no need to allow for funds used during construction for existing units
12 since there is no construction required. OGE has requested that customers pay AFUDC if
13 its proposed asset portfolio recommendations are implemented.
- 14 • No Upward Capital Cost Risk - Existing merchant plants are not subject to the same
15 capital cost pressures affecting other units since they are already complete. These
16 pressures include rising steel, concrete, equipment, construction, labor and engineering
17 costs.
- 18 • No Permitting, Construction and Start-Up Risk - Existing plants are already operating,
19 and hence, not subject to permitting, construction, and start-up risk.
- 20 • Interconnection and Transmission Certainty – Existing plants are already interconnected.
21 By selling into the IM, an operating plant can be monetized directly, or additional firm
22 PtP transmission needs can be considered.

- 1 • Lead Time Risk - Existing plants can be purchased or provide power immediately or a
2 known schedule.
- 3 • Less Environmental Risk – Existing combined cycle plants can be expected to have lower
4 emissions, especially CO2 emissions, than higher heat rate conventional units that have
5 been converted from coal to gas, and decreased environmental risks. Existing simple
6 cycle combustion turbines may also have lower emissions, especially CO2, depending on
7 their age and technology.
- 8 • Sizing Benefit - Many existing power plants may be physically subdivided into separate
9 units, facilitating purchases of less than all of the plant's capacity or output.

10 Additionally, the costs of these existing options may be less than new build, and the costs of
11 conducting an RFP to determine this is low. As a result, the rate impacts might be lower as well.

12 Existing combined cycle plants may also be able to provide PPA options, and the PPA options
13 would create less rate shock if the costs are levelized or otherwise shaped. This could help
14 reduce the risk of customers paying "front-end loaded rates". A capital induced rate increase may
15 be magnified by the need to retrofit existing coal plants with pollution control equipment should
16 the “Scrub” option or “Scrub/Convert” option be implemented.

17

1 **VIII. ICF ANALYSIS OF RESOURCE OPTIONS**

2 **Q. HAVE YOU ANALYZED THE OGE SYSTEM?**

3 **A.** Yes.

4 **Q. HOW WAS THIS DONE?**

5 **A.** We calculated OGE’s Adjusted Production Costs (“APC”) using ICF models and
6 databases and other computer simulation programs. The period of the analysis was 30
7 years and covered the years 2016 to 2045.

8 **Q. WHAT IS APC?**

9 **A.** Adjusted Production Cost equals the sum of the cost of purchasing all utility power
10 requirements at spot market nodal prices in the SPP market and a bilateral or possible
11 future capacity market, less the profits each OGE-owned plant makes in the SPP market
12 from power sales. The APC is calculated annually, but is reported as one present value
13 number, reflecting costs over the 2016-2045 period. The net present value (NPV)
14 calculation reflects a 4.1% real discount rate.⁴⁴

15 **Q. HOW ARE ADJUSTED PRODUCTION COSTS CALCULATED?**

16 **A.** First, we calculated the market-based OGE cost, assuming OGE purchases all utility
17 power requirements at the spot market nodal prices in the SPP market. Market-based
18 capacity costs = Capacity Price * (Peak Demand *(1+Reserve Margin)). Market-based
19 energy costs = Energy Price * Energy Demand. We calculated the market-based OGE
20 capacity and energy cost by assuming OGE is able to purchase this revenue solely from

⁴⁴ This is based on OGE’s reported 8.3% nominal discount rate (see DR *OIEC 3-12_Att85_2014_IRP_RORB_Expenses_Replace_CT*) and an inflation rate of 2.5%.
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1 the market itself, based on market capacity and energy prices. Secondly, we calculated
2 profits for each OG&E plant from energy sales and the capacity market in the SPP
3 market. Adjusted Production Cost is equal to the sum of the costs of purchasing all
4 utility power requirements at spot market nodal prices in the SPP market, less the profits
5 each plant makes in the SPP market from power sales. Profits are net of cash going
6 forward costs. This is similar to the new IM (i.e. dual settlement) nodal market in terms
7 of energy. Since SPP currently has no capacity market, we assumed that the combination
8 of utility-specific resource adequacy requirements and bilateral transactions approximate
9 a capacity market. As is discussed below, we create resource plans that allow OGE to
10 meet its planning reserve margin.

11 **Q. WHAT MODELS DID YOU USE?**

12 **A.** We used IPM®, ICF's proprietary engineering/economic capacity expansion and
13 production-costing model of the power and industrial sectors, supported by an extensive
14 database of every boiler and generator in the nation. IPM is a multi-region model that
15 endogenously determines capacity and transmission expansion plans, unit dispatch and
16 compliance decisions, and power, coal, and allowance price forecasts, all based on power
17 market fundamentals. IPM® explicitly models gas, oil, and coal markets, power plant
18 costs and performance characteristics, environmental constraints, and other power market
19 fundamentals. In the long-run, our least cost capacity expansion model, IPM®, decides
20 for the unplanned build amount and the technology to meet the peak and energy demand.

21 We also used GE-MAPS to assess the nodal price difference from the zonal average price
22 for individual power plants. GE-MAPS performs a chronological security constrained

1 unit commitment (“SCUC”) and security constrained economic dispatch (“SCED”) of
2 generation resources to serve load and reserve requirements, similar to the current
3 implementation in the IM nodal markets in SPP. GE-MAPS is a highly detailed model
4 that chronologically calculates hour-by-hour production costs while recognizing the
5 constraints on the dispatch of generation imposed by the transmission system. GE-MAPS
6 utilizes a detailed electrical model of the entire transmission network, along with
7 generation shift factors that determine how power from generating plants will flow over
8 the alternating current (“AC”) network. This enables GE-MAPS to capture the economic
9 penalties of re-dispatching generation to satisfy transmission line flow limits and security
10 constraints. GE-MAPS captures the hour-by-hour, node-by-node flows of power, given
11 the topology of the grid, the location of power plants, and dozens of other data inputs.
12 IPM[®] provides the following inputs to the GE-MAPS model:

- 13 – Optimal market entry/exit/retrofit decisions
- 14 – Gas Prices
- 15 – Coal and environmental allowance prices

16 **Q. WHAT WERE YOUR KEY ASSUMPTIONS AND CASES?**

17 **A.** The key assumptions and cases include (*see* Attachment C for details):
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**Exhibit ICF-14
Select ICF Key Assumptions**

Parameter	Base Case
Average Henry Hub Natural Gas Price 2016-2045 (2015\$/MMBtu)	[REDACTED]
Average SPP Demand Growth (%)	1.30%
Average Combined Cycle Capital Cost (2015\$/kW)	1,060
Average Heavy-Frame Combustion Turbine Capital Cost (2015\$/kW)	691
Average Wind Capital Cost (2015\$/kW)	1,799
Average Wind Capacity Factor – New Unit (%)	46%
Average CO2 Allowance Cost Price 2016-2033 (2015\$/ton)	[REDACTED]

4 Source: ICF International

5 **Q. HOW DID ICF DEVELOP AND TREAT FOSSIL FUEL FIRED/NON-WIND**
6 **POWER PLANT BUILDS?**

7 **A.** For non-wind power plants, ICF considers capacity as firm for modeling purposes if it
8 meets one of two conditions: 1) a unit is under construction or 2) it meets two of the
9 following three criteria: fully permitted, PPA for greater than 50% of output, or has
10 financing in place for a significant portion of project costs.

11 **Q. HOW DID ICF DEVELOP AND TREAT WIND POWER PLANT BUILDS?**

12 **A.** For wind builds, ICF considers all plants classified as "Under Construction" or
13 "Advanced Development" by SNL Financial ("SNL") as firm. SNL is a provider of news,
14 financial data and analysis on the energy sector and is used by investment professionals.

1 In addition to the SNL research, ICF makes its own estimate of firm wind builds. ICF
2 undertakes this by considering all wind plants that can be identified in the SPP
3 transmission queue that are classified as "IA ON SCHEDULE/FULLY EXECUTED" as
4 firm. ICF performed a detailed analysis matching interconnection queue information
5 with proposed generation from SNL/Ventyx and market sources to identify plants that
6 were in later stages of development. In ICF's modeling, firm builds are typically
7 modeled in the near-term (2014-2018). Firm builds are modeled as new entries with a
8 specific online date and at zero investment cost

9 **Q. HOW LARGE IS THE OVERALL SPP INTERCONENCTION QUEUE OF**
10 **POSSIBLE WIND PLANTS?**

11 **A.** As of November 25, 2014, the SPP-wide Interconnection Queue contained wind
12 generation projects representing more than 11,000 MW.⁴⁵

13 **Q. IS ICF SUGGESTING THAT ALL OF THESE WIND PROJECTS IN THE SPP**
14 **QUEUE ARE LIKELY TO BE BUILT?**

15 **A.** No. Our experience is that some plants in the queue will ultimately be built while others
16 will not. The nature of the risks and costs inherent in the development process means
17 that an estimate of projects/builds that are relatively likely to occur are required. We refer
18 to our modelled "new plant" inputs as "firm" builds.⁴⁶

⁴⁵ SPP July 2014_FINAL_ includes Generation Interconnection queue.pdf

⁴⁶ In this context "firm" is meant to imply a project that can be expected to have a higher level of confidence that it may ultimately be constructed.

1 **Q. HOW DO YOU HANDLE POTENTIAL FEDERAL CO₂ EMISSION**
2 **REGULATIONS?**

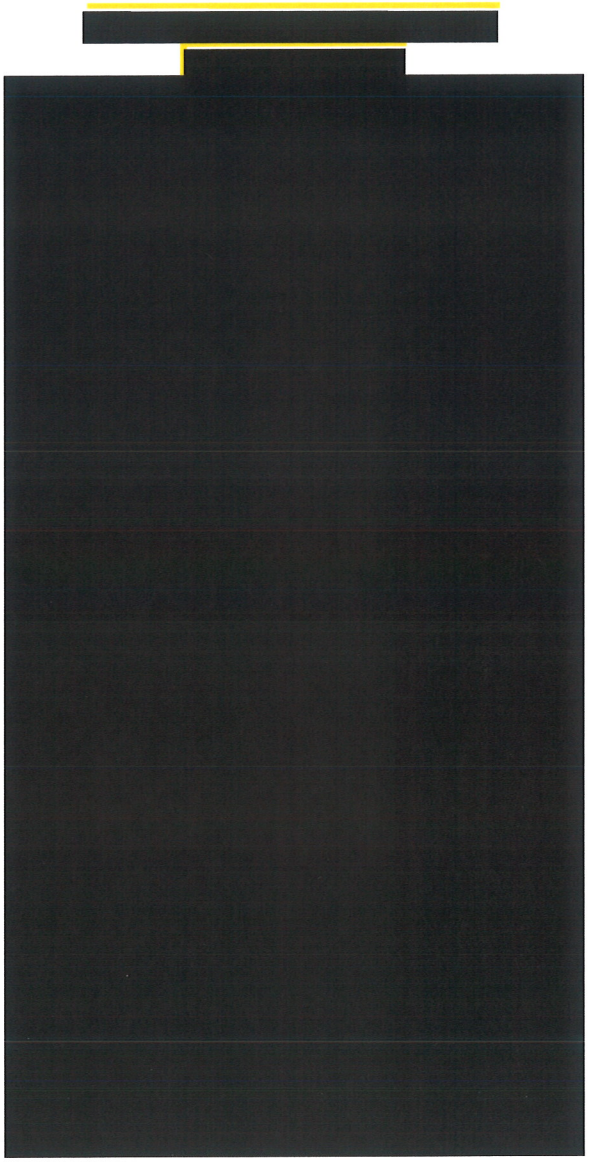
3 **A.** ICF assumes a federal charge on CO₂ from the power sector beginning in 2020, consistent
4 with the timing for the start of EPA's proposed program. The federal CO₂ price stream is
5 a probability-weighted forecast based on three different cases:

- 6 • No CO₂ price (higher near-term probability)
- 7 • National trading program equivalent to reductions from Clean Power Plan
8 (higher mid-term probability)
- 9 • National cap-and-trade consistent with Waxman-Markey (higher long-
10 term probability)

11 CO₂ prices in the ICF Forecast rise from [REDACTED] in 2020
12 to about [REDACTED] in 2030 (see Exhibit ICF-15).

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5 **Q. HOW DO ICF ASSUMPTIONS COMPARE TO OGE'S ASSUMPTIONS?**

6 **A.** ICF assumptions compared to OGE assumptions include:

- 7 ■ **CO₂** – As noted, ICF's base case has CO₂ costs but OGE's Base Case does not.
- 8 OGE's CO₂ sensitivity case has CO₂ costs that are \$16.2/ton on average from
- 9 2020 to 2024 (in 2014\$). In comparison, ICF Base Case forecasts are
- 10 approximately [REDACTED] in 2014 dollars over the same
- 11 period.

- 1 ■ **Natural Gas** - Regarding natural gas prices, between 2016 to 2024, OGE Henry
2 Hub gas prices were \$5.2/MMBtu in 2014 dollars versus ICF prices (OGE IRP
3 case) for 2016 to 2024 of [REDACTED] (in 2014\$).
- 4 ■ **Demand Growth** - Load growth assumptions are the same.
- 5 ■ **General Inflation** - ICF uses a moderately lower inflation rate of 2.1% versus
6 2.5% for OGE.
- 7 ■ **Discount Rate** - OGE used an 8.3% nominal or 5.7% real discount rate which
8 appears to be pre-tax⁴⁷. ICF used a weighted average after tax cost of capital of
9 4.1%.
- 10 ■ **New Unit Costs** - Capital costs for OGE for new gas plants are generally higher
11 than ICF's. Specifically, OGE shows a 560 MW combined cycle at \$1,227/kW
12 overnight in 2014\$ while ICF has \$927/kW (2014\$) for overnight costs. ICF CT
13 costs for an approximately 170 MW plant are \$638/kW (2014\$) on a comparable
14 overnight basis, while OGE CT costs for a 75 MW plant are at \$1,084/kW
15 (2014\$).

16 **Q. WHAT SETS OF RESOURCE OPTIONS DID YOU ANALYZE?**

17 **A. We analyzed the following sets of resource options⁴⁸:**

- 18 ● **OGE 2014 IRP Capacity Expansion Plan:** ICF's view of OGE's 2014
19 IRP.
- 20 ● **Case 1 – 100% PTC Wind with Muskogee Retired:** Sooner retires; buy
21 existing gas plants, buy new gas power plants, and buy wind⁴⁹ 1,900 MW
22 100% PTC qualified to achieve 13.6% operating reserve margin.
- 23 ● **Case 2 – 100% PTC Wind with Muskogee Converted:** Sooner retires;
24 buy existing gas plants, buy new gas power plants, and buy wind 1,900

⁴⁷ OGE gives a nominal WACC of 8.3%. ICF estimated the real WACC of 4.1% for OGE using a debt/equity ratio of 1.0, equity rate of 10.2% and debt rate of 4.57%. All values were compiled from Bloomberg Financial Services, reflecting OGE's latest 2014 SEC filings.

⁴⁸ The options buy new wind and buy existing/new gas power plants are modeled as purchases with recovery equal to a self-build option. This is equivalent quantitatively to a self-build at the same cost or a PPA which provides the same financial recovery of and on capital as a self-build option over time. Options presented by contracting with existing natural gas under PPAs must also be evaluated through an OGE RFP to determine cost savings and other benefits. There is no opinion expressed as to which approach is preferred.

⁴⁹ ICF calculates customer savings based on wind on line starting in 2018. To the extent the wind comes on line earlier in 2016, the savings would be higher. New wind and existing gas power plants are modeled as purchases with recovery equal to a self-build option.

1 MW 100% PTC qualified, plus convert Muskogee from coal powered to
2 natural gas powered to achieve 13.6% operating reserve margin.

3 • **Case 3 – 50% PTC Wind with Muskogee Retired:** Sooner retires; Buy
4 existing gas plants, buy new gas power plants, and buy wind 1,900 MW
5 50% PTC qualified/50% not PTC qualified to achieve 13.6% operating
6 reserve margin.

7 • **Case 4 – 50% PTC Wind with Muskogee Converted:** Sooner retires;
8 buy existing gas plants, buy new gas power plants and buy wind 1,900
9 MW 50% PTC qualified/50% not PTC qualified plus convert Muskogee
10 Units 4 and 5 from coal powered to natural gas powered to achieve 13.6%
11 operating reserve margin.

12 • **Case 5 – 0% PTC Wind with Muskogee Retired:** Sooner retires; buy
13 existing gas plants, buy new gas power plants, and buy wind 1,900 MW
14 0% PTC-qualified to achieve 13.6% operating reserve margin.

15 • **Case 6 – 0% PTC Wind with Muskogee Converted:** Sooner retires; buy
16 existing gas plants, buy new gas power plants and buy wind 1,900 MW
17 0% PTC-qualified plus convert Muskogee Units 4 and 5 from coal to
18 natural gas fuel to achieve 13.6% reserve margin

19 **Q. WHAT WERE THE CAPACITY REQUIREMENTS AND HOW WERE THEY**
20 **FULFILLED IN EACH PLAN EXAMINED?**

21 **A.** SPP requires all its members to maintain a capacity margin of 12%, which implies a
22 reserve margin requirement of 13.6%. In order to meet the reserve margin requirements,
23 ICF makes the following modeling assumptions on a case-by-case basis.

24 **OGE 2014 Expansion Capacity Plan** (see Exhibit ICF-16): This represents ICF's
25 analysis and assessment of OGE's IRP. We model Sooner 1 (in 2018) and Sooner 2 (in
26 2020) to retrofit with LSD at a cost of \$530/kW and to retrofit with ACI at a cost \$24/kW
27 (2014\$). Muskogee Units 4 and 5 (nominal 1000 MW) converts from coal to natural gas
28 in 2020 at a cost of 35.7 \$/kW (2014\$); Starting in 2018, Mustang Units 1-4 (460 MW) is
29 replaced by 10 units of combustion turbines rated at 40 MW each at a cost of 1002 \$/kW

1 (2014\$)⁵⁰. Starting in 2023 we add additional CT capacity to meet reserve margin
2 requirements.⁵¹

3 **100% PTC Qualified Wind (Cases 1 and 2):** Under these cases, Sooner 1 and Sooner 2
4 are retired in 2018 and 2020, respectively. ICF models new wind build⁵² of 1,900 MW at
5 a cost of \$1799/kW (2015\$). Including the benefits of PTC at 100%, the total new wind
6 capital cost is approximately 866\$/kW (2015\$). Muskogee is retired in Case 1 in 2020
7 (see Exhibit ICF-17), but converted from coal to natural gas in 2020 at a cost of \$36/kW
8 (2015\$) in Case 2 (see Exhibit ICF-18). We assume [REDACTED]

9 [REDACTED] is available to be purchased in 2018 at a cost of [REDACTED]

10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED] To meet reserve margin requirements we also add 700
14 MW of a new CC in 2020 at a cost of \$1,060/kW (2015\$). When needed new heavy
15 frame CTs are built at a cost of 691\$/kW (2015\$) in 100 MW incremental blocks to meet
16 the 13.6% reserve margin requirement.

17 **50% PTC Wind (Cases 3 and 4):** The steps taken in these cases are also identical to the
18 100% PTC cases in the paragraph above [Case 3 corresponds to Case 1 (see Exhibit ICF-
19 17), and Case 4 corresponds to Case 2 (see Exhibit ICF-18)], except that we attribute

⁵⁰ Capital costs for Sooner and Muskogee are given in 2014\$ in the .OGE 2014 IRP filing,

⁵¹ We model new CT builds starting in 2023 at a cost of 1084\$/kW (2014\$) in incremental 75 MW blocks as necessary in each year that there is a violation. There is no new wind added.

⁵² SPP recognized approximately 5% of nameplate wind capacity for capacity margin purposes.

1 50% of the PTC benefit to the new wind build of 1,900 MW, reflecting a total new wind
2 build capital cost of approximately 1,332\$/kW (2015\$).

3 **0% PTC Wind (Cases 5 and 6):** The steps taken in these cases are also identical to the
4 100% PTC cases in the paragraph above [Case 5 corresponds to Case 1 (see Exhibit ICF-
5 17), and Case 6 corresponds to Case 2 (see Exhibit ICF-18)], except that we attribute 0%
6 PTC benefit to the new wind build of 1,900 MW, reflecting a total wind build capital cost
7 of 1,799\$/kW.

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**Exhibit ICF-16
OGE 2014 IRP Capacity Expansion Plan**

Year	OG&E Peak Demand (MW)	Retire OG&E Cap (MW)	Converting Muskogee (MW)	Build New CT (MW)	Summer Net Capacity contributing to RM (MW)	Reserve Margin	Purchase from Market (MW)
2015					6876		
2016	5793	0	0	0	6876	18.7%	0
2017	5848	0	0	0	6876	17.6%	0
2018	5858	32	0	0	6844	16.8%	0
2019	5902	32	0	0	6844	16.0%	0
2020	5920	1061	998	0	6813	15.1%	0
2021	5962	1061	998	0	6813	14.3%	0
2022	5992	1061	998	0	6813	13.7%	0
2023	6032	1061	998	75	6888	14.2%	0
2024	6078	1061	998	75	6888	13.3%	17
2025	6118	1061	998	150	6963	13.8%	0
2026	6159	1061	998	150	6963	13.1%	33
2027	6199	1061	998	225	7038	13.5%	4
2028	6240	1061	998	300	7113	14.0%	0
2029	6281	1061	998	300	7113	13.2%	23
2030	6323	1061	998	375	7188	13.7%	0
2031	6365	1061	998	450	7263	14.1%	0
2032	6407	1061	998	450	7263	13.4%	15
2033	6449	1061	998	525	7338	13.8%	0
2034	6492	1061	998	525	7338	13.0%	37
2035	6535	1061	998	600	7413	13.4%	10
2036	6578	1061	998	675	7488	13.8%	0
2037	6621	1061	998	675	7488	13.1%	34
2038	6665	1061	998	750	7563	13.5%	8
2039	6709	1061	998	825	7638	13.8%	0
2040	6753	1061	998	825	7638	13.1%	34
2041	6798	1061	998	900	7713	13.5%	9
2042	6843	1061	998	975	7788	13.8%	0
2043	6888	1061	998	1050	7863	14.2%	0
2044	6934	1061	998	1050	7863	13.4%	14
2045	6979	1061	998	1125	7938	13.7%	0

Source: ICF International and based in part on OGE's 2014 IRP.

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[REDACTED]

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[REDACTED]

[REDACTED]

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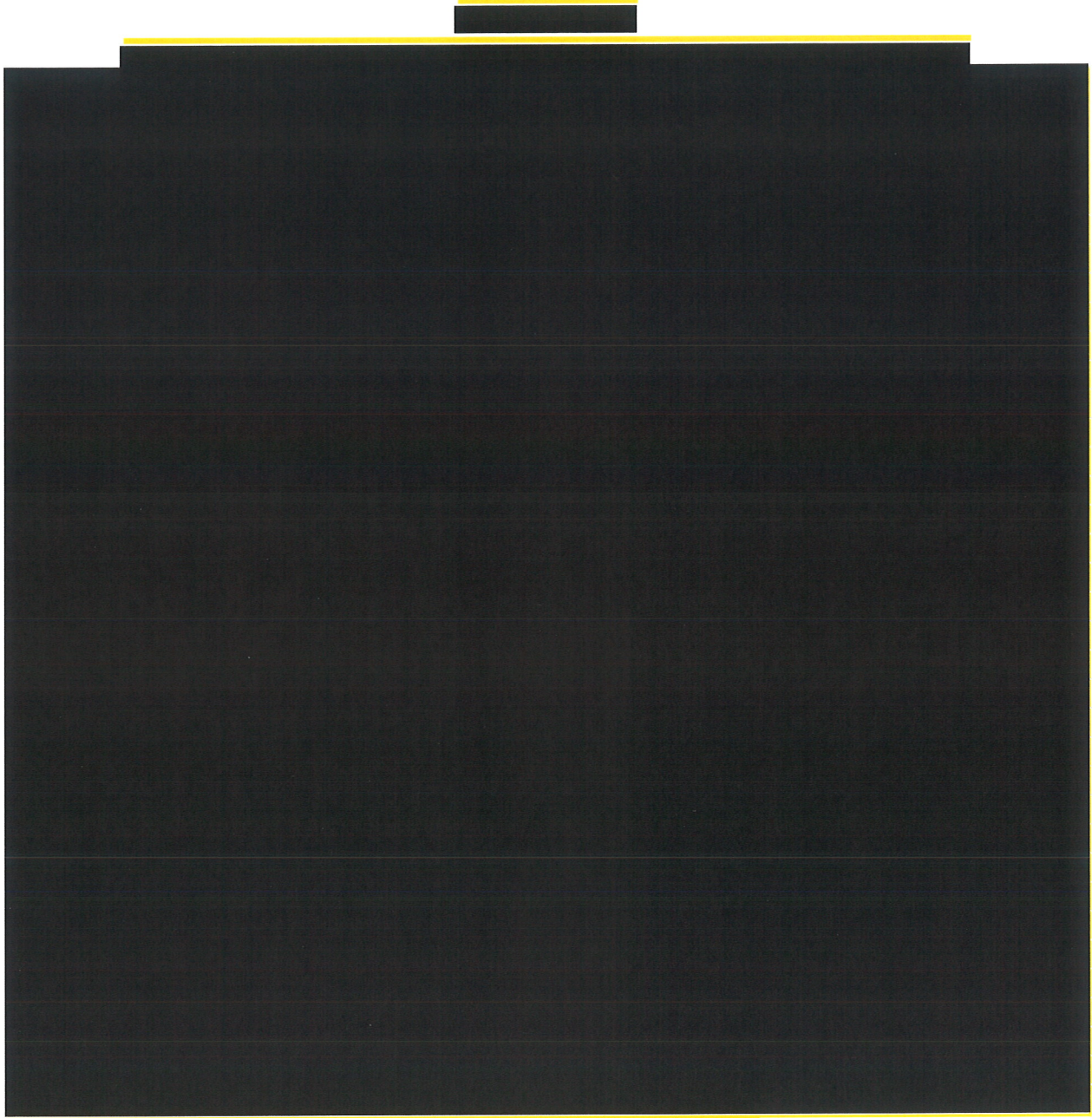
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[REDACTED]

Exhibit ICF-18

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1 **Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS?**

2

3 **A.** Case 1 (100% PTC Wind with Muskogee Retired) is estimated to save \$3.0 billion (2015
4 \$) on a NPV basis compared to OGE 2014 IRP Capacity Expansion Plan. This is a
5 decrease of approximately 9%, and results in a very significant savings. In Case 2 (100%
6 PTC Wind with Muskogee Converted) is estimated to save \$3.3 billion (2015\$)
7 compared to OGE 2014 IRP Capacity Expansion Plan (See Exhibit ICF-19). This is a
8 decrease of approximately 10%, and results in a very significant savings. Please refer to
9 Attachment D for details.

█ [REDACTED]

█ [REDACTED]

█ [REDACTED]

13 [REDACTED]

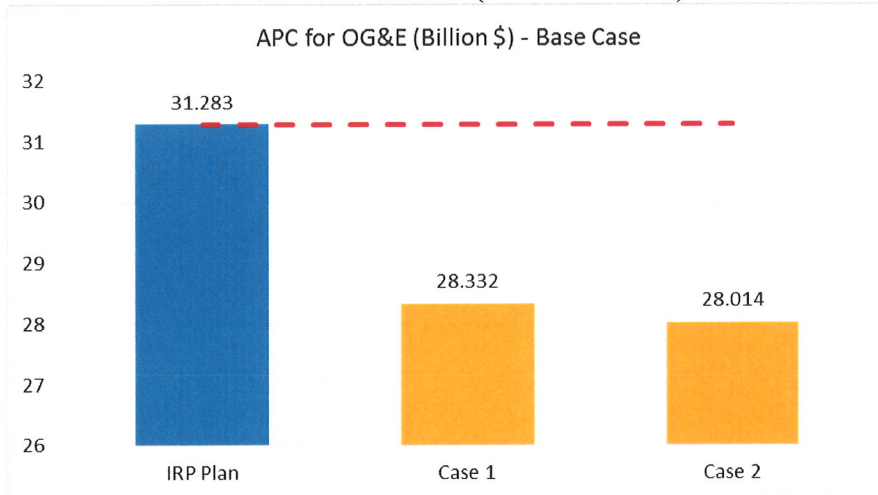
█ [REDACTED] It is interesting to note that an EPA study shows that [REDACTED]
15 [REDACTED] that is sufficiently large enough to support a conversion for Muskogee to gas
16 would cost approximately \$215/kW. If this is accurate, our Case 1 scenario would result
17 in a slightly lower cost than ICF’s Case 2.

18

⁵⁴ EPA, “Documentation Supplement for EPA Base Case v4.10_PTox- Updates for Proposed Toxics Rule”, March 2011, shows that an estimate [REDACTED] to convert Muskogee from coal to gas would cost approximately \$215/kW.

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Exhibit ICF-19 Base Case Results (2015\$ Billions)



Source: ICF International
 Notes: IRP Plan - OGE 2014 IRP Capacity Expansion Plan
 Case 1 - 100% PTC Wind with Muskogee Retired, saves \$3.0 billion (2015\$)
 Case 2 - 100% PTC Wind with Muskogee Converted, saves \$3.3 billion (2015\$)

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9 **Q. WERE YOUR RESULTS SENSITIVE TO THE AMOUNT OF PTC-QUALIFIED**
10 **WIND?**

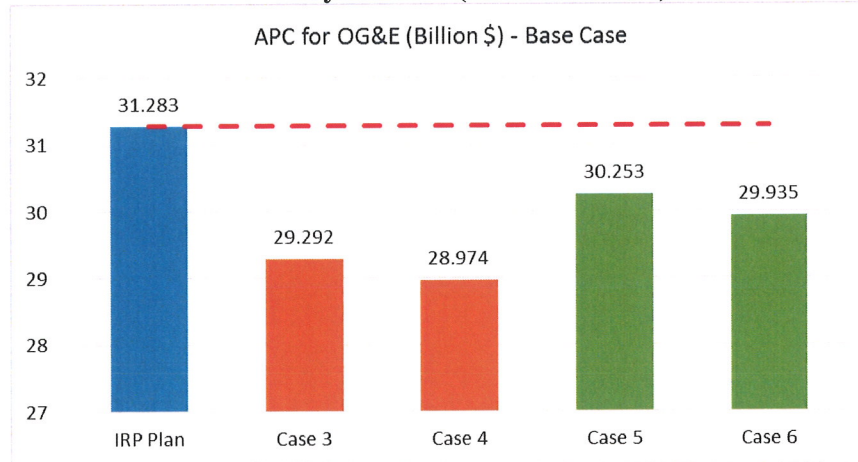
11 **A.** Yes. Compared to OGE 2014 IRP Capacity Expansion Plan, Case 3 (50% PTC Wind
12 with Muskogee Retired) saved approximately \$2.0 billion (2015\$), and Case 4 (50% PTC
13 Wind with Muskogee Converted) saved \$2.3 billion (2015\$). Even without the PTC,
14 Case 5 (0% PTC Wind with Muskogee Retired) and Case 6 (0% PTC Wind with
15 Muskogee Converted) saved \$1.0 billion (2015\$)⁵⁵ and \$1.3 billion (2015\$), respectively,
16 compared to the OGE IRP Capacity Expansion Plan. Thus, it is critical that the wind and
17 existing gas options be fully examined (see Exhibit ICF-20).

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⁵⁵ The largest source of benefit in this case is wind. Most of this benefit is due to CO2 emission regulations which raise the price of energy in the IM.

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Exhibit ICF-20 PTC Sensitivity Results (2015\$ Billions)



Source: ICF International
 Notes: IRP Plan - OGE 2014 IRP Capacity Expansion Plan
 Case 3 - 50% PTC Wind with Muskogee Retired, saves \$2.0 billion (2015\$)
 Case 4 - 50% PTC Wind with Muskogee Converted, saves \$2.3 billion (2015\$)
 Case 5 - 0% PTC Wind with Muskogee Retired, saves \$1.0 billion (2015\$)
 Case 6 - 0% PTC Wind with Muskogee Converted, saves \$1.3 billion (2015\$)

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11 **Q. WERE YOUR RESULTS SENSITIVE TO CURTAILMENT AND CONGESTION RISK?**

12

13 **A.** No. We did not find large discounts at the nodes examined (approximately 8% before
 14 planned upgrades). Also, even if curtailment occurred enough of the time to decrease net
 15 capacity factor by 18%⁵⁶ - i.e. from 46% to 28%, and OGE was required to absorb these
 16 costs, the options examined with 1,900 MW of PTC qualified wind were still as
 17 economic as the OGE plan. We are not aware of such a high level of sustained
 18 curtailment in other regions There is no evidence of this level being possible for a
 19 sustained period. In the extremely unlikely event that curtailment could reach such high
 20 levels, under FERC Order 890, it is SPP's responsibility to resolve significant and
 21 recurring congestion such as this. This highlights that transmission problems are unlikely

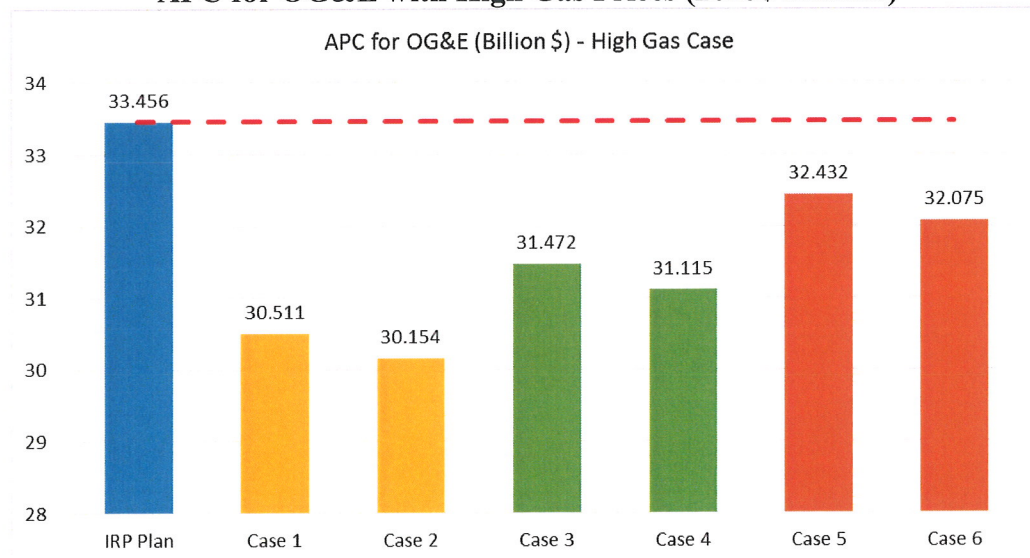
⁵⁶ This number was derived using a breakeven analysis between Case 1 and the OGE 2014 IRP Capacity Expansion Plan.
 Judah L. Rose Responsive Testimony Cause No. PUD 201400229
 Oklahoma Energy Results, LLC

1 to alter the conclusions that available PTC qualified wind should be a key component of a
2 least cost plan.

3 **Q. WHAT SENSITIVITIES DID YOU ANALYZE?**

4 **A.** We analyzed low and high gas prices by varying the price by \$1/MMBtu relative to the
5 reference case values. We found the results not very sensitive to the gas price
6 assumptions. While the total cost to serve load for OGE went up by approximately 7% in
7 the high case and down by 14% in the low case the net savings did not change
8 significantly in either case relative to the Base Case. Compared to the OGE 2014 IRP
9 Capacity Expansion Plan, all the ICF Analysis cases had lower APC and the cases with
10 100% PTC qualified wind had the lowest APC (see Exhibit ICF-21 and Exhibit ICF-22).

11 **Exhibit ICF-21**
12 **APC for OG&E with High Gas Prices (2015\$ Billions)**
13



14 Source: ICF International

15 Notes: IRP Plan - OGE 2014 IRP Capacity Expansion Plan

16 Case 1 - 100% PTC Wind with Muskogee Retired, saves \$2.9 billion (2015\$)

17 Case 2 - 100% PTC Wind with Muskogee Converted, saves \$3.3 billion (2015\$)

18 Case 3 - 50% PTC Wind with Muskogee Retired, saves \$2.0 billion (2015\$)

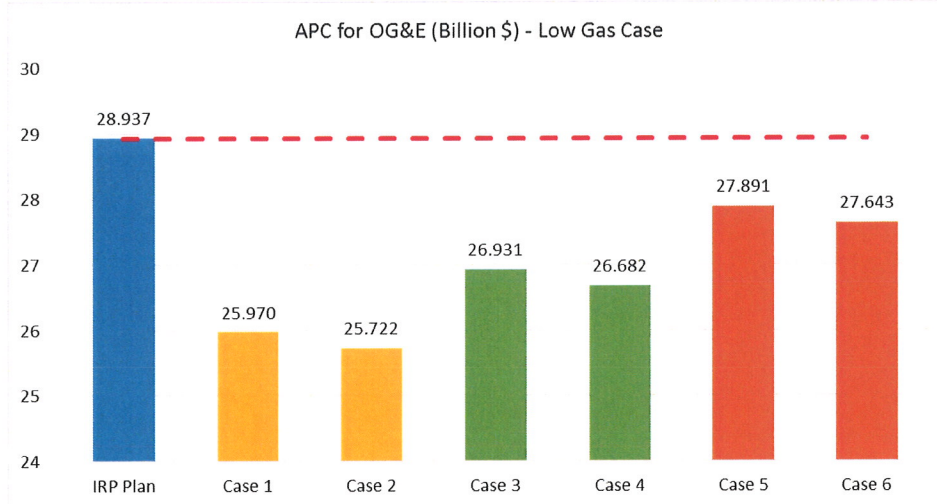
19 Case 4 - 50% PTC Wind with Muskogee Converted, saves \$2.3 billion (2015\$)

20 Case 5 - 0% PTC Wind with Muskogee Retired, saves \$1.0 billion (2015\$)

21 Case 6 - 0% PTC Wind with Muskogee Converted, saves \$1.4 billion (2015\$)

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Exhibit ICF-22 APC for OG&E with Low Gas Prices (2015\$ Billions)



Source: ICF International

Notes: IRP Plan - OGE 2014 IRP Capacity Expansion Plan

- Case 1 - 100% PTC Wind with Muskogee Retired, saves \$3.0 billion (2015\$)
- Case 2 - 100% PTC Wind with Muskogee Converted, saves \$3.2 billion (2015\$)
- Case 3 - 50% PTC Wind with Muskogee Retired, saves \$2.0 billion (2015\$)
- Case 4 - 50% PTC Wind with Muskogee Converted, saves \$2.3 billion (2015\$)
- Case 5 - 0% PTC Wind with Muskogee Retired, saves \$1.0 billion (2015\$)
- Case 6 - 0% PTC Wind with Muskogee Converted, saves \$1.3 billion (2015\$)

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12 **Q. DID YOU REVIEW OTHER SENSITIVITIES?**

13 **A.** Yes. We considered the impacts of an increase in wind capacity factors from 46% to 49%

14 on all wind cases. With higher wind capacity factor, APC decreased approximately \$0.4

15 billion (2015\$) for all cases, which increased the difference between OGE 2014 IRP

16 Capacity Expansion Plan and Case 1 (100% PTC Wind with Muskogee Retired) to \$3.3

17 billion (2015\$), and the difference between OGE 2014 IRP Capacity Expansion Plan and

18 Case 2 (100% PTC Wind with Muskogee Converted) to \$3.6 billion (2015\$).

19

1 **IX. CONCLUSIONS**

2 **Q. IN A BROADER CONTEXT, WHAT ARE THE IMPLICATIONS OF THESE**
3 **RESULTS?**

4 **A.** There are several implications. First, we found that there were a number of cases using
5 PTC qualified wind and existing natural gas portfolio combinations that resulted in
6 several projected lower cost potential resource portfolios to OGE customers of up to \$3.3
7 billion. These benefits accrue while maintaining planning reserve margins.

8 **Q. ARE YOU SUGGESTING THE ASSETS THAT SHOULD BE PART OF AN OGE**
9 **RESOURCE PLAN?**

10 **A.** No. This is the responsibility of OGE to develop. Rather, our results should be
11 interpreted as an effort to suggest that more planning needs to be done, and a greater
12 number of alternatives need to be considered.

13 **Q. WHAT ARE YOUR CONCLUSIONS?**

14 **A.** My review of the current situation facing OGE, its planning, and its proposal for
15 compliance with Regional Haze regulations leads to the following conclusions:

16 ■ OGE did not conduct RFPs or up to date RFIs for PTC qualified wind and
17 existing natural gas power plants. OGE did not quantitatively analyze PTC
18 qualified wind and existing natural gas power plant options. ICF analyzed the
19 expected costs of these options and found alternatives with potentially
20 substantially lower costs.

21 ■ *In light of finding large potential expected savings, the full and complete*
22 *assessment of the availability of PTC qualified wind while maintaining operating*

1 *reserve margin requirements is critical and OGE must complete this assessment*
2 *before proceeding under its or any proposed IRP. RFPs that provide market tests*
3 *are required for PTC qualified wind and for existing natural gas power plants.*
4 Without including this more comprehensive assessment into OGE's IRP,
5 including quantitative analysis of the capacity and energy contributions of PTC
6 qualified wind, and combinations of PTC qualified wind and existing natural gas
7 power plants, and associated transmission considerations an IRP process that
8 requires consideration of least cost criteria is fatally flawed.

9 ■ Depending on the amount of PTC qualified wind in Oklahoma, ICF's analysis
10 indicates very large customer savings. The projected savings are in proportion to
11 the amount of PTC qualified wind available. For example, in a scenario with
12 1900 MW⁵⁷ of PTC qualified wind in combination with existing and new gas
13 fired power plants, the Net Present Value of Savings of Adjusted Production
14 Costs (APC) compared to the OGE IRP plan is projected to be \$3.0 to \$3.3
15 billion. Other scenarios with less PTC qualified wind have lower savings.

16 ■ Thus, ICF's analysis confirms that to the extent that it is available, the federal
17 Production Tax Credit (PTC) for wind power plants of approximately 2.3 cents
18 per kilowatt hour creates very significant customer cost savings opportunities,
19 especially when combined with high capacity factor wind. Furthermore, multiple

⁵⁷ 2,400 MW would produce approximately the same amount of energy as the Sooner coal power plant, though with a different profile and other characteristics from Sooner output. Hence, ICF conducted a detailed analysis. See later discussion.

1 options are likely available to back up wind with natural gas power plants
2 including existing units.

- 3 ■ OGE’s decision not to analyze the wind options and associated transmission
4 issues is a serious deficiency. Such an analysis would include a nodal analysis
5 similar to ICF’s and other analyses including assessment of the availability of
6 firm transmission. ICF estimates that the discount of nodal prices for PTC
7 qualified wind units in the Integrated Marketplace[1] (“IM”) will be
8 approximately 7 to 8% relative to the zonal average without the Woodward-
9 Tatonga-Matthewson-Cimarron transmission upgrade program currently
10 scheduled for 2021 and approximately 3% with the Woodward-Tatonga-
11 Matthewson-Cimarron transmission upgrade program. . This discount is factored
12 into our analysis, and furthermore, the benefits (estimated at \$3.0 billion to \$3.3
13 billion in one case) provide significant ability to pay for transmission upgrades if
14 needed to obtain firm transmission service from SPP. Lastly, the SPP IM has
15 introduced marginal losses into its price determination; this was not part of the
16 EIS (the previous SPP market construct). Accordingly, many generators are
17 experiencing discounts, not just wind plants.

- 18 ■ OGE also based its decision in part to screen out wind options on its stated
19 uncertainty about the viability of wind options. However, the options OGE
20 considered have similar or larger amounts of uncertainty, and hence, OGE’s
21 exclusion of the wind option results in an analysis that is biased against wind.

22 OGE also based its decision to screen out wind on the lack of capacity

1 contribution from wind. The need for capacity can be addressed by a combination
2 of wind and thermal generation capacity. Natural gas generation in particular
3 represents an attractive potential option.

4 ■ Unlike OGE's Base Case in its own IRP process, ICF's Base Case analysis
5 accounts for potential CO₂ emission regulations which favor wind over coal
6 options, all else equal. There is a reasonable method for accounting for potential
7 CO₂ regulations such as the proposed CPP, and it is important that proper weight
8 be given to their potential impact in the Base Case. Furthermore, the wind and
9 gas options provide a hedge against future tightening of environmental
10 regulations. Specific building blocks of the EPA evaluation process for the CPP
11 used to determine the emission reduction requirements include a focus on re-
12 dispatch to gas which could result in an increase in the capacity factor of
13 combined cycle plants. In Oklahoma, the focus was on re-dispatch of generation
14 that could yield capacity factors as high as 70% for combined cycle natural gas
15 fired plants. Overall, this could be considerably higher than the experience of
16 recent years. Moreover, in the event that federal CO₂ emission regulations are
17 implemented, existing gas and wind additions, even without PTC qualified wind,
18 provide savings to customers of \$1.0 to \$1.4 billion. Most of the benefits in the
19 non-PTC cases accrue as a result of the higher energy prices in the IM caused by
20 CO₂ regulations.

21 ■ Expeditious and timely action is required to take advantage of the amount of PTC
22 qualified wind facilities. OGE's RFI for wind in 2013 is not sufficiently up to

1 date. OGE should not go forward until it can demonstrate that PTC qualified
2 wind opportunities have been fully considered, and that OGE has acted to avoid
3 losing available opportunities. The consideration should include sufficient
4 analysis of the energy benefits of the wind opportunities including assessment of
5 congestion, curtailment, and firm transmission service. OGE should conduct
6 market-based solicitations or RFPs for PTC qualified wind and existing natural
7 gas generation capacity to provide back-up capacity for the wind to confirm
8 whether a lower cost alternative exists to its proposed plan.

- 9 ■ The Mustang “modernization” or repowering also requires an IRP with a
10 complete wind and wind gas assessment. This is because some of the options
11 (Sooner retrofit/Muskogee convert) change such a significant part of the OGE
12 system. The Mustang decision also requires a market test. A market test is
13 important because it may identify lower cost options that could reduce the overall
14 cost of the resulting portfolio to OGE customers. We have identified

15 [REDACTED]

16 [REDACTED] The availability
17 of alternative existing natural gas generation capacity should be determined
18 through an RFP.

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**ATTACHMENT A
ROSE RESUME**

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JUDAH L. ROSE

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EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

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EXPERIENCE

Judah L. Rose joined ICF in 1982 and currently serves as a Managing Director of ICF International. Mr. Rose directs ICF's Wholesale Power practice and co-chairs its Energy Advisory and Solution Line of Business. Mr. Rose has approximately 35 years of experience in the energy industry including in electricity generation, fuels, environmental compliance, planning, finance, forecasting, and transmission. Mr. Rose's clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, and Independent Power Producers. Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 5,000 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative.

Mr. Rose frequently provides expert testimony and litigation support. Mr. Rose has provided testimony in over 120 instances in scores of state, federal, international, and other legal proceedings. Mr. Rose has testified in over 24 states and provinces, at the Federal Energy Regulatory Commission, in numerous court settings and internationally.

Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community in restructuring and financing.

Mr. Rose has also addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies. Mr. Rose has also appeared in TV interviews.

Mr. Rose received a M.P.P. from the John F. Kennedy School of Government, Harvard University, and an S.B. in Economics from the Massachusetts Institute of Technology.

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Judah L. Rose Responsive Testimony
Oklahoma Energy Results, LLC

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19 Testimony to Louisiana Public Service Commission, December 1996.
- 20 5. "Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets." Testimony on
21 a contract arbitration, Las Vegas, Nevada, June 1996.
- 22 4. "Future Rate Paths and the Cajun Bankruptcy." Testimony to the U.S. Bankruptcy Court, June 1997.
- 23 3. "Fuel Prices and Coal Transportation." Testimony to the U.S. Bankruptcy Court, June 1997.
- 24 2. "Demand for Gas Pipeline Capacity in Florida from Electric Utilities." Testimony to Florida Public
25 Service Commission, May 1993.
- 26 1. "The Case for Fuel Flexibility in the Florida Electric Generation Industry." Testimony to the
27 Florida Department of Environmental Regulation (Der), Hearings on Fuel Diversity and
28 Environmental Protection, December 1992.

29

30

31 **SELECTED SPEAKING ENGAGEMENTS**

32

- 1 115. Rose, J.L., The Polar Vortex, System Reliability and Recent PJM Developments, American
2 Municipal Power Conference, October 28, 2014.
3
4 114. Rose, J.L., Wholesale power Market Price Projection in California, Infocast, California Energy
5 Summit, San Francisco, CA, May 28, 2014.
6
7 113. Rose, J.L., The Polar Vortex and Future Power system Trends, National Coal Council, 2014 Annual
8 Spring Meeting, May 14, 2014.
9
10 112. Rose, J.L., The Polar Vortex and System Reliability, The Energy Authority (TEA), Jacksonville, FL,
11 April 30, 2014.
12
13 111. Rose, J.L., Utility and Transco Plans and Transmission Projects to Deal with the Changing
14 Generation Resource Mix, Panel Moderator, Transmission Summit Panel Discussion, March 14,
15 2014.
16
17 110. Rose, J.L., Examining Natural Gas and Power Price Dynamics During the Polar Vortex, APPA,
18 March 10, 2014.
19
20 109. Rose, J.L., Polar Vortex – Skating too Close to the Edge, First Friday Club, March 7, 2014.
21
22 108. Rose, J.L., New Developments in the California Power Market, Infocast California Energy
23 Summit, San Francisco, CA, December 3, 2013.
24
25 107. Rose, J.L., Financial Issues in Determining the Disposition of Fossil Power Plants, Managing the
26 Power Plant Decommissioning, Decontamination, and Demolition Process, November 7, 2013.
27
28 106. Rose, J.L, Reality and Impacts of Plant Retirements, Reading Tea Leaves – The Future of
29 America’s Installed Power Plants, July 25, 2013.
30
31 105. Rose, J.L., Financial issues in Determining the Disposition of Fossil Power Plants, Plant
32 Decommissioning, Decontamination, and Demolition, May 9, 2013.
33
34 104. Rose, J.L., Financial Issues in Determining the Disposition of Plant Decommissioning,
35 Decontamination & Demolition Summit, Infocast, May 1, 2013.
36
37 103. Rose, J.L., Implications of Current Low Natural Gas Price Environment on Wholesale Power,
38 Edison Electric Institute, May 3, 2012.
39
40 102. Rose, J.L., Anticipating the Next Turn in a Gas-Rich Environment, Key Pricing Drivers, and
41 Outlook, Houlihan and Lokey Merchant Energy Conference, April, 24, 2012.
42
43 101. Rose, J.L., CREPC/SPSC Natural Gas – Electricity in West Panel, San Diego, April 3, 2012
44
45 100. Rose, J.L., EUCI Financing Transmission Expansion, San Diego, CA, March 8-9, 2011.
46

- 1 99. Rose, J.L., Vinson & Elkins Conference, Houston, TX, November 11, 2010.
- 2
- 3 98. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Crystal City, Arlington, VA,
- 4 June 29-30, 2010.
- 5
- 6 97. Rose, J.L., Economics of PC Refurbishment, Improving the Efficiency of Coal-Fired Power
- 7 Generation in the U.S., DOE-NETL, February 24, 2010.
- 8
- 9 96. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Orlando, FL, January 25-26, 2010.
- 10
- 11 95. Rose, J.L., CO₂ Control, "Cap & Trade", & Selected Energy Issues, Multi-Housing Laundry
- 12 Association, October 26, 2009.
- 13
- 14 94. Rose, J.L., Financing for the Future – Can We Afford It?, 2009 Bonbright Conference, October 9,
- 15 2009.
- 16
- 17 93. Rose, J.L., EEI's Transmission and Market Design School, Washington, D.C., June 2009.
- 18
- 19 92. Rose, J.L., ICF's New York City Energy Forum - Market Recovery in Merchant Generation Assets,
- 20 June 10, 2008.
- 21
- 22 91. Rose, J.L., Southeastern Electric Exchange – Integrated Resource Planning Task Force Meeting,
- 23 Carbon Tax Outlook Discussion, February 21-22, 2008.
- 24
- 25 90. Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic
- 26 Future, Marlborough, MA, October 23, 2006.
- 27
- 28 89. Rose, J.L., Infocast Gas Storage Conference, "Estimating the Growth Potential for Gas-Fired
- 29 Electric Generation," Houston, TX, March 22, 2006.
- 30
- 31 88. Rose, J.L., "Power Market Trends Impacting the Value of Power Assets," Infocast Conference,
- 32 Powering Up for a New Era of Power Generation M&A, February 23, 2006.
- 33
- 34 87. Rose, J.L., "The Challenge Posed by Rising Fuel and Power Costs", Lehman Brothers, November
- 35 2, 2005.
- 36
- 37 86. Rose, J.L., "Modeling the Vulnerability of the Power Sector", EUCI – Securing the Nation's Energy
- 38 Infrastructure, September 19, 2005
- 39
- 40 85. Rose, J.L., "Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting,
- 41 New York, NY, June 9, 2005.
- 42
- 43 84. Rose, J.L., "2005 Macquarie Utility Sector Conference", Macquarie Utility Sector Conference,
- 44 Vail, CO, February 28, 2005.
- 45

- 1 83. Rose, J.L., "The Outlook for North American Natural Gas and Power Markets", The Institute for
2 Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.
3
- 4 82. Rose, J.L. "Assessing the Salability of Merchant Assets – What's on the Horizon?" Infocast – The
5 Market for Power Assets, Phoenix, AZ, February 10, 2005.
6
- 7 81. Rose, J.L. "Market Based Approaches to Transmission – Longer-Term Role", National Group of
8 Municipal Bond Investors, New York, NY, December 10, 2004.
9
- 10 80. Rose, J.L. "Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term
11 Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.
12
- 13 79. Rose, J.L. "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's
14 Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.
15
- 16 78. Rose, J. L. "After the Blackout – Questions That Every Regulator Should be Asking," NARUC
17 Webinar Conference, Fairfax, VA, November 6, 2003.
18
- 19 77. Rose, J. L., "Supply and Demand in U.S. Wholesale Power Markets," Lehman Brothers Global
20 Credit Conference, New York, NY, November 5, 2003.
21
- 22 76. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's
23 Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.
24
- 25 75. Rose, J.L., "Asset Valuation in Today's Market", Infocast's Project Finance Tutorial, New York,
26 NY, October 8, 2003.
- 27 74. Rose, J.L., "Forensic Evaluation of Problem Projects", Infocast's Project Finance Workouts:
28 Dealing With Distressed Energy Projects, September 17, 2003.
- 29 73. Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.
- 30 72. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's
31 Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.
- 32 71. Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New
33 York, NY, "Spark Spread Outlook", July 17, 2003.
- 34 70. Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., "Trends in U.S. Energy and
35 Economy", June 24, 2003.

- 1 69. Rose, J.L., "Power Markets: Prices, SMD, Transmission Access, and Trading", Bechtel
2 Management Seminar, Frederick, MD, June 10, 2003.
- 3 68. Rose, J.L., Platt's Global Power Market Conference, New Orleans, LA, "The Outlook for
4 Recovery," March 31, 2003.
- 5 67. Rose, J.L., "Electricity Transmission and Grid Security", Energy Security Conference, Crystal City,
6 VA, March 25, 2003.
- 7 66. Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's
8 Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.
- 9 65. Rose, J.L., Panel Discussion, "Forensic Evaluation of Problem Projects", Infocast Conference, NY,
10 February 24, 2003.
- 11 64. Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).
- 12 63. Rose, J.L., "The Merchant Power Market—Where Do We Go From Here?" Center for Business
13 Intelligence's Financing U.S. Power Projects, November 18-19, 2002.
- 14 62. Rose, J.L., "Assessing U.S. Regional and the Potential for Additional Coal-Fired Generation in
15 Each Region," Infocast's Building New Coal-Fired Generation Conference, October 8, 2002.
- 16 61. Rose, J.L., "Predicting the Price of Power for Asset Valuation in the Merchant Power Financings,
17 "Infocast's Product Structuring in the Real World Conference, September 25, 2002.
- 18 60. Rose, J.L., "PJM Price Outlook," Platt's Annual PJM Regional Conference, September 24, 2002.
- 19 59. Rose, J.L., "Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than
20 Exotic & Complicated Technologies," New York Venture Group's Investing in the Power Industry—
21 Targeting The Newest Trends Conference, July 31, 2002.
- 22 58. Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant
23 Conference 2002, May 15, 2002.
- 24 57. Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured
25 Finance Institute, April 8-9, 2002.
- 26 56. Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference,
27 November 6, 2001.
- 28 55. Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply
29 Chain Conference, Web Presented Conference, September 12, 2002.
- 30 54. Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game
31 Conference, September 6, 2001
- 32 53. Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance
33 Capital Markets Conference, New York NY, June 27 2001

- 1 52. Rose, J.L., "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry
2 Association, Boca Raton Florida, June 25, 2001
- 3 51. Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power
4 Development and Finance Conference 2001, Washington D.C., June 12, 2001
- 5 50. Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in
6 western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001
- 7 49. Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California,
8 February 12, 2001
- 9 48. Rose, J.L., "An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000"
10 Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.
- 11 47. Rose, J. L., "An Analysis of the Power Markets, summer 2000" Generation Panel Presentation,
12 Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000.
- 13 46. Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference
14 Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000
- 15 45. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair,
16 Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.
- 17 44. Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract
18 (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19,
19 1999.
- 20 43. Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas,
21 October 26-28, 1999.
- 22 42. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair
23 Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.
- 24 41. Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power
25 Conference, New York, New York, September 24, 1999.
- 26 40. Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The
27 Future of Electric Transmission Conference, Washington, DC, September 13, 1999.
- 28 39. Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote
29 Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington,
30 DC, July 14, 1999.
- 31 38. Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage
32 Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.
- 33 37. Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy
34 Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.
- 35 36. Rose, J.L., "Repowering Existing Power Plants and Its Impact on Market Prices" presentation,
36 Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.

- 1 35. Rose, J.L., "Transmission and Retail Issues in the Electric Industry" Session Speaker, Gas
2 Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.
- 3 34. Rose, J.L., "Peak Price Volatility in the Rockies and Southwest" presentation at Repowering the
4 Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.
- 5 33. Rose, J.L., "Understanding Generation" presentation and Program Chairman at Buying & Selling
6 Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.
- 7 32. Rose, J.L., "Buying Generation Assets in PJM" presentation at Mid-Atlantic Power Summit,
8 Philadelphia, Pennsylvania, April 12, 1999.
- 9 31. Rose, J.L., "Evaluating Your Generation Options in Situations With Insufficient Transmission,"
10 presentation at Congestion Management Conference, Washington, D.C., March 25, 1999.
- 11 30. Rose, J.L., "Will Capacity Prices Drive Future Power Prices?" presentation at Merchant Plant
12 Development Conference, Chicago, Illinois, March 23, 1999.
- 13 29. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting
14 Conference, Atlanta, Georgia, February 25, 1999
- 15 28. Rose, J.L., "Developing Reasonable Expectations About Financing New Merchant Plants That
16 Have Less Competitive Advantage Than Current Projects," presentation at Project Finance
17 International's Financing Power Projects in the USA conference, New York, New York, February
18 11, 1999.
- 19 27. Rose, J.L., "Transmission and Capacity Pricing and Constraints," presentation at Power Fair 99,
20 Houston, Texas, February 4, 1999.
- 21 26. Rose, J.L., "Peak Price Volatility: Comparing ERCOT With Other Regions," presentation at
22 Megawatt Daily's Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.
- 23 25. Rose, J.L., "The Outlook for Midwest Power Markets," presentation to The Institute for
24 Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.
- 25 24. Rose, J.L., "Developing Pricing Strategies for Generation Assets," presentation at Wholesale
26 Power in the West conference, Las Vegas, Nevada, November 12, 1998.
- 27 23. Rose, J.L., "Understanding Electricity Generation and Deregulated Wholesale Power Prices," a
28 full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.
- 29 22. Rose, J.L., "The Impact of Power Generation Upgrades, Merchant Plant Developments, New
30 Transmission Projects and Upgrades on Power Prices," presentation at Profiting in the New York
31 Power Market conference, New York, NY, October 22, 1998.
- 32 21. Rose, J.L., "Capacity Value – Pricing Firmness," presentation to Edison Electric Institute
33 Economics Committee, Charlotte, NC, October 8, 1998.
- 34 20. Rose, J.L., "Locational Marginal Pricing and Futures Trading," presentation at Megawatt Daily's
35 Electricity Regulation conference, Washington, D.C., October 7, 1998.
- 36 19. Rose, J.L., Chairman's opening speech and "The Move Toward a Decentralized Approach: How
37 Will Nodal Pricing Impact Power Markets?" at Congestion Pricing and Tariffs conference,
38 Washington, D.C., September 25, 1998.

- 1 18. Rose, J.L., "The Generation Market in MAPP/MAIN: An Overview," presentation at Megawatt
2 Daily's MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16,
3 1998.
- 4 17. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting
5 conference, Baltimore, Maryland, August 24, 1998.
- 6 16. Rose, J.L., "ICF Kaiser's Wholesale Power Market Model," presentation at Market Price
7 Forecasting conference, New York, New York, August 6, 1998.
- 8 15. Rose, J.L., Campbell, R., Kathan, David, "Valuing Assets and Companies in M&A Transactions,"
9 full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.
- 10 14. Rose, J.L., "Must-Run Nuclear Generation's Impact on Price Forecasting and Operations,"
11 presentation at The Energy Institute's conference entitled "Buying and Selling Electricity in the
12 Wholesale Power Market," Las Vegas, Nevada, June 25, 1998.
- 13 13. Rose, J.L., "The Generation Market in PJM," presentation at Megawatt Daily's PJM Power
14 Markets conference, Philadelphia, Pennsylvania, June 17, 1998.
- 15 12. Rose, J.L., "Market Evaluation of Electric Generating Assets in the Northeast," presentation at
16 McGraw-Hill's conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15,
17 1998.
- 18 11. Rose, J.L., "Overview of SERC Power," opening speech presented at Megawatt Daily's SERC Power
19 Markets conference, Atlanta, Georgia, May 20, 1998.
- 20 10. Rose, J.L., "Future Price Forecasting," presentation at The Southeast Energy Buyers Summit,
21 Atlanta, Georgia, May 7, 1998.
- 22 9. Rose, J.L., "Practical Risk Management in the Power Industry," presentation at Power Fair,
23 Toronto, Canada, April 16, 1998.
- 24 8. Rose, J.L., "The Wholesale Power Market in ERCOT: Transmission Issues," presentation at
25 Megawatt Daily's ERCOT Power Markets conference, Houston, Texas, April 1, 1998.
- 26 7. Rose, J.L., "New Generation Projects and Merchant Capacity Coming On-Line," presentation at
27 Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.
- 28 6. Rose, J.L., "Projecting Market Prices in a Deregulated Electricity Market," presentation at
29 conference: Market Price Forecasting, San Francisco, California, March 9, 1998.
- 30 5. Rose, J.L., "Handling of Transmission Rights," presentation at conference: Congestion Pricing &
31 Tariffs, Washington, D.C., January 23, 1998.
- 32 4. Rose, J.L., "Understanding Wholesale Markets and Power Marketing," presentation at The Power
33 Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.
- 34 3. Rose, J.L., "Determining the Electricity Forward Curve," presentation at seminar: Pricing,
35 Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October
36 23, 1997.

37

- 1 2. Rose, J.L., "Market Price Forecasting In A Deregulated Market," presentation at conference:
2 Market Price Forecasting, Washington, D.C., October 23, 1997,
- 3 1. Rose, J.L., "Credit Risk Versus Commodity Risk," presentation at conference: Developing &
4 Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16,
5 1997.

6

7

8 **SELECTED PUBLICATIONS**

9

- 10 Rose, J.L., "Return of the RTO: Auction Results Portend Recovery," White Paper, June 14, 2014.
- 11 Rose, J. L., "The Next Polar Vortex: How Long Will Grid Emergencies and Price Volatility Continue?"
12 Public Utilities Fortnightly, June 2014.
- 13 Rose, J.L., "Wind Curtailment, Assessing and Mitigating Risks," White Paper, December 2012.
- 14 Rose, J.L. and Henning, B. "Partners in Reliability: Gas and Electricity," PowerNews, September 1, 2012.
- 15 Rose, J.L. and Surana, S. "Using Yield Curves and Energy Prices to Forecast Recessions – An Update."
16 World Generation, March/April 2011, V.23 #2.
- 17 Rose, J.L. and Surana, S. "Oil Price Increases, Yield Curve Inversion may be Indicators of Economic
18 Recession." Oil and Gas Financial Journal, Volume 7, Issue 6, June 2010
- 19 Rose, J.L. and Surana, S. "Forecasting Recessions and Investment Strategies." World-Generation,
20 June/July 2010, V.22, #3.
- 21 Rose, J.L., "Should Environmental Restrictions be Eased to Allow for the Construction of More Power
22 Plants? The Costco Connection, April 2001.
- 23 Rose, J.L., "Deregulation in the US Generation Sector: A Mid-Course Appraisal", Power Economics,
24 October 2000.
- 25 Rose, J. L., "Price Spike Reality: Debunking the Myth of Failed Markets", *Public Utilities Fortnightly*,
26 November 1, 2000.
- 27 Rose, J.L., "Missed Opportunity: What's Right and Wrong in the FERC Staff Report on the Midwest Price
28 Spikes," *Public Utilities Fortnightly*, November 15, 1998.
- 29 Rose, J.L., "Why the June Price Spike Was Not a Fluke," *The Electricity Journal*, November 1998.
- 30 Rose, J.L., S. Muthiah, and J. Spencer, "Will Wall Street Rescue the Competitive Wholesale Power Market?"
31 *Project Finance International*, May 1998.

1 Rose, J.L., "Last Summer's "Pure" Capacity Prices – A Harbinger of Things to Come," *Public Utilities*
2 *Fortnightly*, December 1, 1997.

3 Rose, J.L., D. Kathan, and J. Spencer "Electricity Deregulation in the New England States," *Energy Buyer*,
4 Volume 1, Issue 10, June-July 1997.

5 Rose, J.L., S. Muthiah, and M. Fusco, "Financial Engineering in the Power Sector," *The Electricity Journal*,
6 Jan/Feb 1997.

7 Rose, J.L., S. Muthiah, and M. Fusco, "Is Competition Lacking in Generation? (And Why it Should Not
8 Matter)," *Public Utilities Fortnightly*, January 1, 1997.

9 Mann, C. and J.L. Rose, "Price Risk Management: Electric Power vs. Natural Gas," *Public Utilities Fortnightly*,
10 February 1996.

11 Rose, J.L. and C. Mann, "Unbundling the Electric Capacity Price in a Deregulated Commodity Market,"
12 *Public Utilities Fortnightly*, December 1995.

13 Booth, William and J.L. Rose, "FERC's Hourly System Lambda Data as Interim Bulk Power Price Information,"
14 *Public Utilities Fortnightly*, May 1, 1995.

15 Rose, J.L. and M. Frevert, "Natural Gas: The Power Generation Fuel for the 1990s." Published by Enron.
16

17

18 **EMPLOYMENT HISTORY**

19	ICF Resources Incorporated	Managing Director	1999-Present
20		Vice President	1996-1999
21		Project Manager	1993-1996
22		Senior Associate	1986-1993
23		Associate	1982-1986

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B.1 EPA’s Clean Power Plan (CPP) Background

The Clean Power Plan (CPP) proposes to regulate CO₂ emissions from existing fossil fuel generation sources under Section 111(d) of the Clean Air Act. The EPA defines “existing” as construction that has commenced before January 8, 2014. The EPA proposed a rule under Section 111(b) for new sources in September 2013.

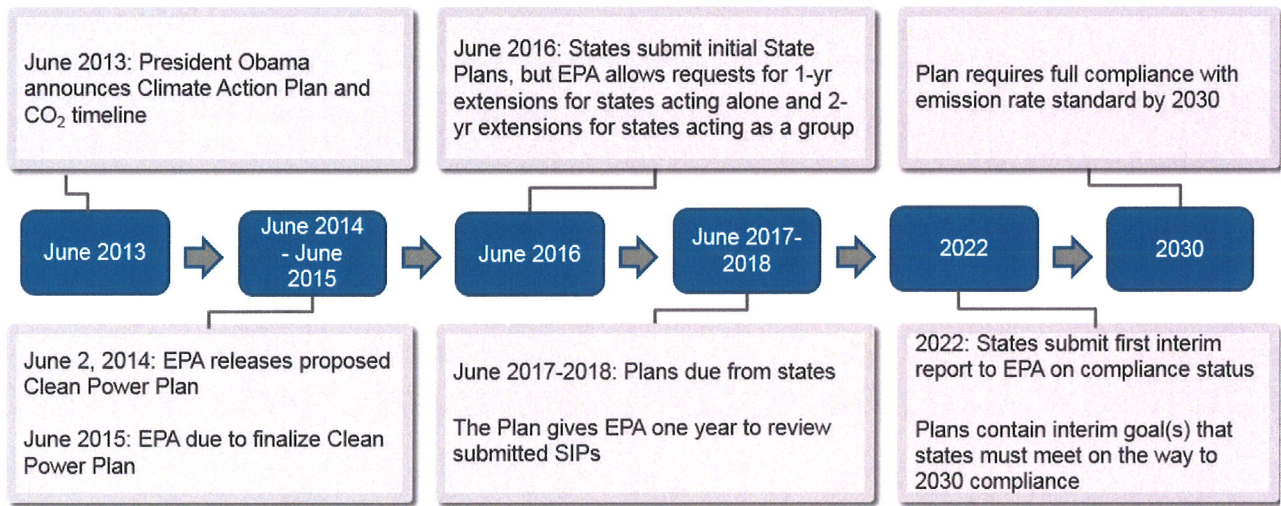
The EPA released the CPP rule on Monday, June 2, 2014, in-line with President Obama’s Climate Action Plan. The EPA took comments on the proposal through October 16, 2014, following publication in Federal Register on June 18, 2014.

The EPA estimates that the program will reduce power sector emissions 30% below 2005 levels in 2030.

B.2 Timeline for EPA’s Proposed CPP

Exhibit ICF B-1 shows a timeline for EPA’s proposed clean power plan.

**Exhibit ICF B-1
Timeline for EPA’s Proposed CPP**



Source: ICF International

B.3 Possible Challenges to EPA’s Timeline

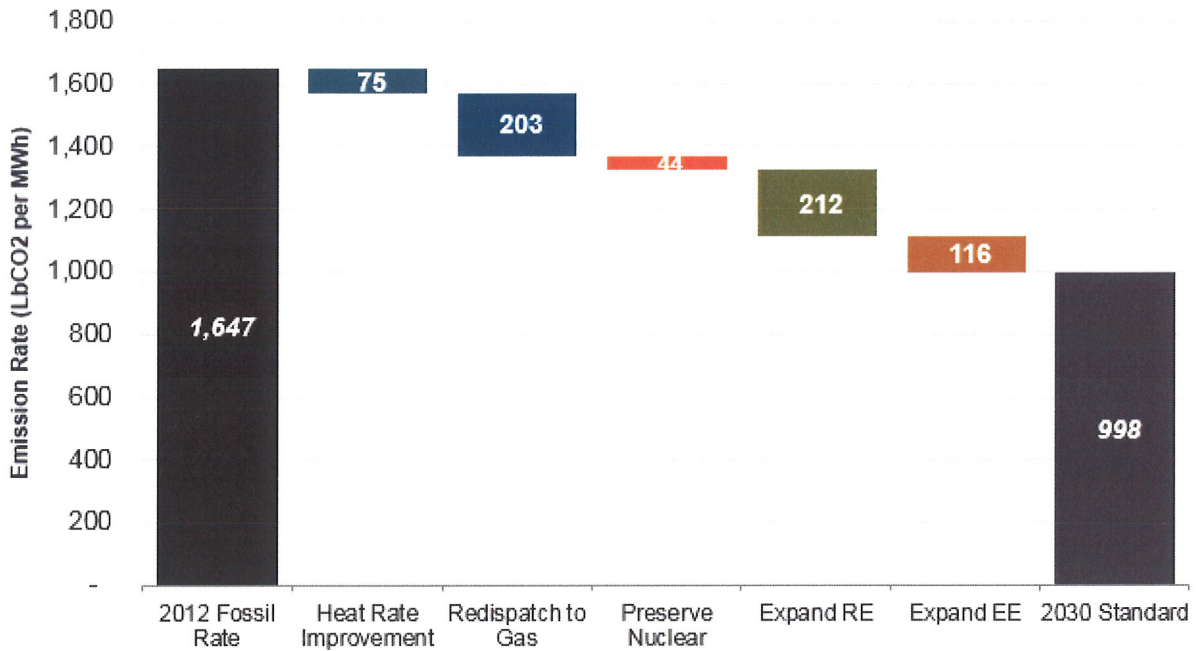
The plan will likely face legal challenges following release of the final rule in 2015. There is also potential for the program to be delayed given expected legal challenges to EPA’s proposed 111(b), or new source, rule.

1 **B.4 Building Blocks Determining Standards**

2 Exhibit ICF B-2 shows the building blocks that determine standards (U.S. average).

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**Exhibit ICF B-2
Timeline for EPA's Proposed CPP**



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Source: ICF International

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C.1 Demand Levels

Exhibit ICF C-1 shows peak demand and energy projections for SPP and OG&E from 2016-2045. ICF took 2013 SPP demand levels from 2013 NERC ES&D. ICF applied a growth rate of 1.29% and 1.32% to energy and net internal demand respectively to produce the forecast from 2016-2045. The growth rates are from SPP’s 2013 Integrated Transmission Plan.

1
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Exhibit ICF C-1 SPP and OG&E Peak Demand and Energy Projections

Year	SPP		OG&E	
	Energy (GWh)	Net Internal Demand (MW)	Energy (GWh)	Net Internal Demand (MW)
2016	268,743	55,311	29,740	5,793
2017	272,215	56,041	30,062	5,848
2018	275,732	56,781	30,284	5,858
2019	279,295	57,530	30,561	5,902
2020	282,903	58,289	30,816	5,920
2021	286,558	59,059	31,000	5,962
2022	290,261	59,838	31,222	5,992
2023	294,011	60,628	31,485	6,032
2024	297,810	61,429	31,728	6,078
2025	301,657	62,239	31,960	6,118
2026	305,555	63,061	32,194	6,159
2027	309,502	63,893	32,430	6,199
2028	313,501	64,737	32,667	6,240
2029	317,552	65,591	32,906	6,281
2030	321,654	66,457	33,147	6,323
2031	325,810	67,334	33,389	6,365
2032	330,020	68,223	33,634	6,407
2033	334,284	69,124	33,880	6,449
2034	338,603	70,036	34,128	6,492
2035	342,977	70,961	34,378	6,535
2036	347,409	71,897	34,629	6,578
2037	351,897	72,846	34,883	6,621
2038	356,444	73,808	35,138	6,665
2039	361,049	74,782	35,395	6,709
2040	365,714	75,769	35,654	6,753
2041	370,439	76,770	35,915	6,798
2042	375,225	77,783	36,178	6,843
2043	380,073	78,810	36,443	6,888
2044	384,983	79,850	36,709	6,934
2045	389,957	80,904	36,978	6,979
Average 2016-2045	325,728	67,326	33,318	6,357

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Sources: SPP's 2013 ITP20, NERC ES&D Released Dec 2013, OG&E 2014 IRP

Notes:

- [1] 2013 demand levels taken from 2013 NERC ES&D
- [2] ICF chose the ITP20 as it is the most recent released document from SPP (July 2013). Other demand projections were considered, including NERC 2013 ES&D's projections (Dec 2013), NERC's 2013 LTRA projections (Nov 2013), data from EIA 411 (2012) and an average of historical demands. ICF feels that the ITP20 demand is the most recent and reasonable.
- [2] Both Energy and Peak Demand are Net and not gross numbers, taken from NERC ES&D's 2013 values
- [3] From 2016-2024, OG&E energy and peak demand numbers are taken from the 2014 OG&E IRP
- [4] From 2025-2045, OG&E net peak and energy numbers are grown at the last 5 year growth rate (2020-2024)
- [5] OG&E energy and peak demand numbers are including contribution both from energy efficiency and demand response

1 **C.2 Demand Side Management**

2 Demand Side Management (DSM) assumptions utilized in this assessment reflect DSM
 3 projections from the NERC 2013 ES&D, released in December 2013. After 2024, ICF assumes
 4 that DR remains as a percentage of peak load remains flat. Exhibit ICF C-2 provides the DSM
 5 forecast for SPP between 2016 and 2045. Exhibit ICF C-3 provides the O&GE’s DSM forecast.

6 **Exhibit ICF C-2**
 7 **SPP’s Demand Response and Energy Efficiency**

Year	Demand Resources (MW)	Energy Efficiency (MW)	Total DSM (MW)
2016	1,275	427	1,702
2017	1,329	509	1,837
2018	1,281	605	1,886
2019	1,248	709	1,957
2020	1,207	810	2,017
2021	1,251	903	2,154
2022	1,526	976	2,502
2023	1,539	1,014	2,553
2024	1,541	1,040	2,581
2025	1,561	1,054	2,615
2026	1,582	1,068	2,650
2027	1,603	1,082	2,685
2028	1,624	1,096	2,720
2029	1,645	1,110	2,756
2030	1,667	1,125	2,792
2031	1,689	1,140	2,829
2032	1,711	1,155	2,866
2033	1,734	1,170	2,904
2034	1,757	1,186	2,943
2035	1,780	1,201	2,981
2036	1,804	1,217	3,021
2037	1,827	1,233	3,061
2038	1,852	1,249	3,101
2039	1,876	1,266	3,142
2040	1,901	1,283	3,183
2041	1,926	1,300	3,226
2042	1,951	1,317	3,268
2043	1,977	1,334	3,311
2044	2,003	1,352	3,355
2045	2,030	1,370	3,399

8 *Source: NERC 2013 ES&D*

9 **Notes:**

10 [1] SPP numbers are based on NERC 2013 ES&D, released December 2013

11 [2] Post 2024, DR is projected to remain at same percentage of peak load.

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**Exhibit ICF C-3
OG&E's Demand Response and Energy Efficiency**

Year	Demand Response (MW)	Energy Efficiency (MW)	Total DSM (MW)
2016	412	47	459
2017	429	58	487
2018	449	70	519
2019	453	81	534
2020	257	93	350
2021	462	104	566
2022	466	103	569
2023	470	103	573
2024	471	102	573
2025	474	103	577
2026	477	103	581
2027	480	104	585
2028	484	105	589
2029	487	106	593
2030	490	107	597

3 *Source: 2014 OG&E IRP*

4 **C.3 Reserve Margin Targets**

5 As shown in Exhibit ICF C-4, target reserve margins are from the July 2014 release of the SPP
6 Long-Term Reliability Assessment. SPP requires its members to maintain 12% capacity margin
7 or in other words a 13.6% target reserve margin.

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**Exhibit ICF C-4
Projected Target Reserve Margin Assumptions**

Region/sub-Region	RM Target
SPP	13.6%
OG&E	13.6%

12 *Source: SPP LTRA 2014*

13 **C.4 New Power Plant Capital Costs**

14 Capital cost assumptions for SPP are presented in Exhibit ICF C-5. Wind costs do not include
15 the Production Tax Credit (PTC). Capital costs assumptions are based on ICF's work and
16 analysis with developers, utilities, IPPs and financing entities.

**Exhibit ICF C-5
ICF Capital Costs Assumptions – SPP Region (2015\$/kW)**

Year	Combined Cycle	Combustion Turbine	LMS 100	Nuclear	Wind
2016		691	963		1,799
2018	1,061	691	963		1,799
2020	1,061	691	963		1,799
2025	1,061	691	963	6,605	1,799
2030	1,061	691	963	6,605	1,799
2037	1,061	691	963	6,605	1,799
2045	1,061	691	963	6,605	1,799

Source: ICF International

Notes:

- (1) CC builds are allowed only in 2017 onwards due to lead time limitations
- (2) CT builds are allowed from 2016 onwards due to lead time limitations
- (3) Capital costs are adjusted for summer weather and altitude conditions.
- (4) Nuclear builds are allowed online in 2024 onwards due to lead time limitations.
- (5) Wind costs above do not include the Production Tax Credit (PTC).

C.5 Natural Gas Prices

Exhibit ICF C-6 presents our natural gas price forecast in 2015\$ for both the OGE capacity Expansion plan and Cases 1 through 6. Exhibit ICF C-7 presents our delivered gas prices in 2015\$ for both the OGE capacity Expansion plan and Cases 1 through 6.

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Judah L. Rose Responsive Testimony
Oklahoma Energy Results, LLC

Cause No. PUD 201400229

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Judah L. Rose Responsive Testimony
Oklahoma Energy Results, LLC

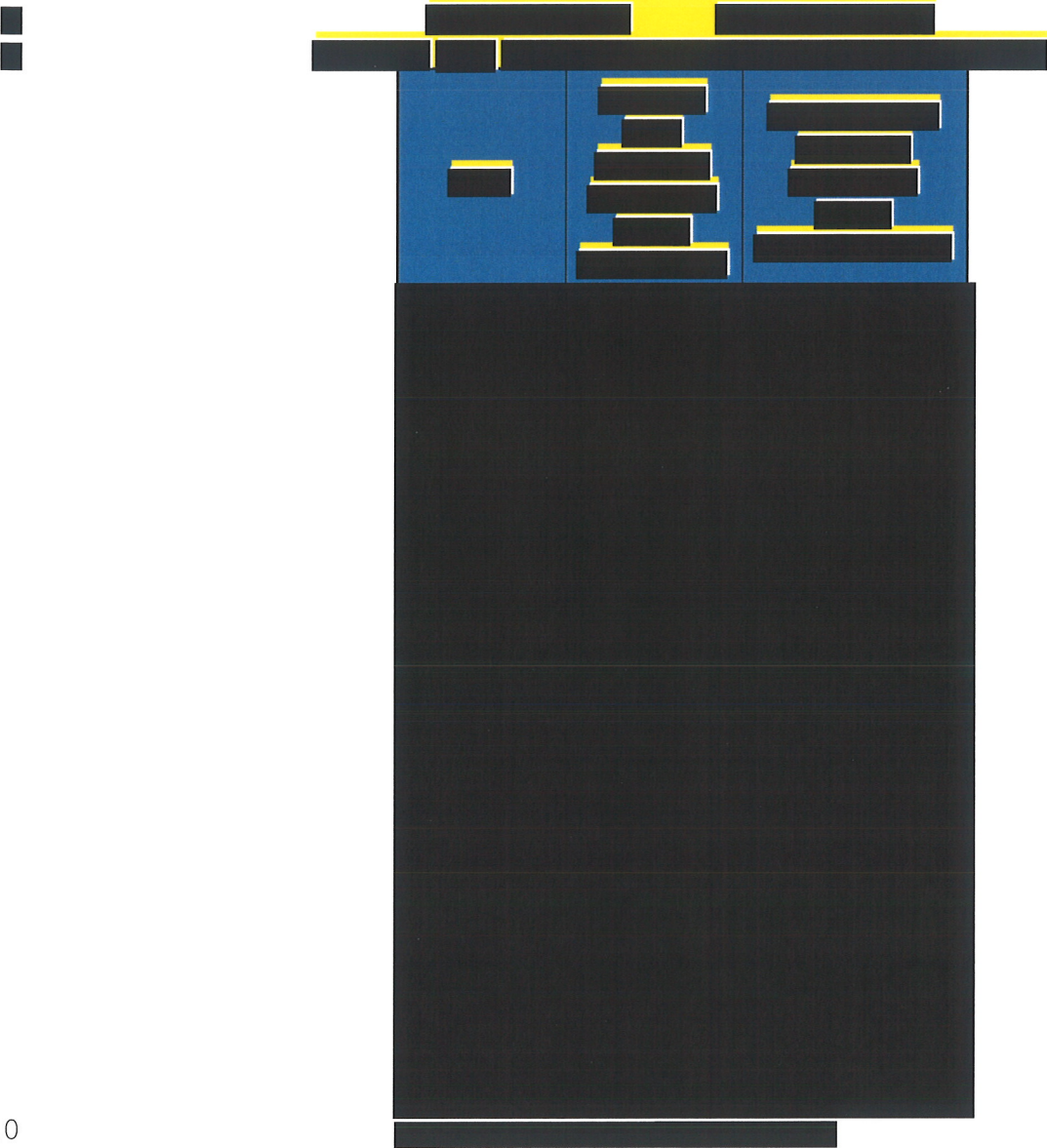
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2 **C.6 Greenhouse Gases (CO₂)**

3 While not imminent, ICF believes it is still likely that a national CO₂ price signal will come into
4 being at some point, at least for the power sector. To reflect this assumption, ICF's Base Case
5 analysis includes the initiation of a national CO₂ policy starting 2020 with an average price of
6 approximately [REDACTED] (2015\$) in 2020 increasing to
7 [REDACTED] (2015\$) by 2033 (see Exhibit ICF C-8).



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1 **C.7 OG&E Portfolio Overview**

2 Exhibit ICF C-9 below summarizes the OGE portfolio as of 2014.

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4 **Exhibit ICF C-9**
5 **OG&E Portfolio Capacity Summary (MW) of the OG&E Portfolio (as of 2014)**

Prime Mover	Power Plant	Installed Capacity (MW)	Reserve Margin Capacity (MW)
OG&E Coal Portfolio	Muskogee 4 -5	998	998
	Muskogee 6	500	500
	Sooner 1	520	520
	Sooner 2	522	522
	Shady Point 1	160	160
	Shady Point 2	160	160
OG&E Gas Portfolio	McClain Energy Center	380	380
	Horse Shoe Lake 6 & 8	563	563
	Horse Shoe Lake 7	193	193
	Horse Shoe Lake 9 & 10	90	90
	Mustang 1-4	463	463
	Mustang 5A & 5B	70	70
	Seminole 1 -3	1457	1457
	Seminole GT1	16	16
	Red Bud	622	622
	Powersmith	120	120
	Blackwell Wind	60	3
	Centennial Wind Farm	120	6
	OU Spirit	101	5
OG&E Wind Portfolio	Taloga	130	7
	Keenan Wind Farm	152	8
	Cross Roads Wind Farm	227	11
	FPL Wind	50	3
	Total	-	7,674

6 **Source:** ICF, OG&E IRP 2014

7 **Notes:**

8 [1] SPP recognized approximately 5% of nameplate wind generation for capacity margin
9 purposes.

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3 **D.1 Adjusted Production Cost Results**

4 Exhibit ICF D-1, ICF D-2 and ICF D-3 show ICF's APC results for the OGE portfolio under the
5 base, high and low gas price cases respectively. All results are shown in 2015\$. The period of
6 analysis covered 30 years from 2016 to 2045. The net present value shown reflects a 4.1% real
7 discount rate.

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E.1 Energy Price Results

Exhibit ICF E-1, ICF E-2 and ICF E-3 show ICF's energy price forecasts for the OGE control area under the Base, high and low gas price cases respectively. All results are shown in 2015\$. The period of analysis covered 30 years from 2016 to 2045.

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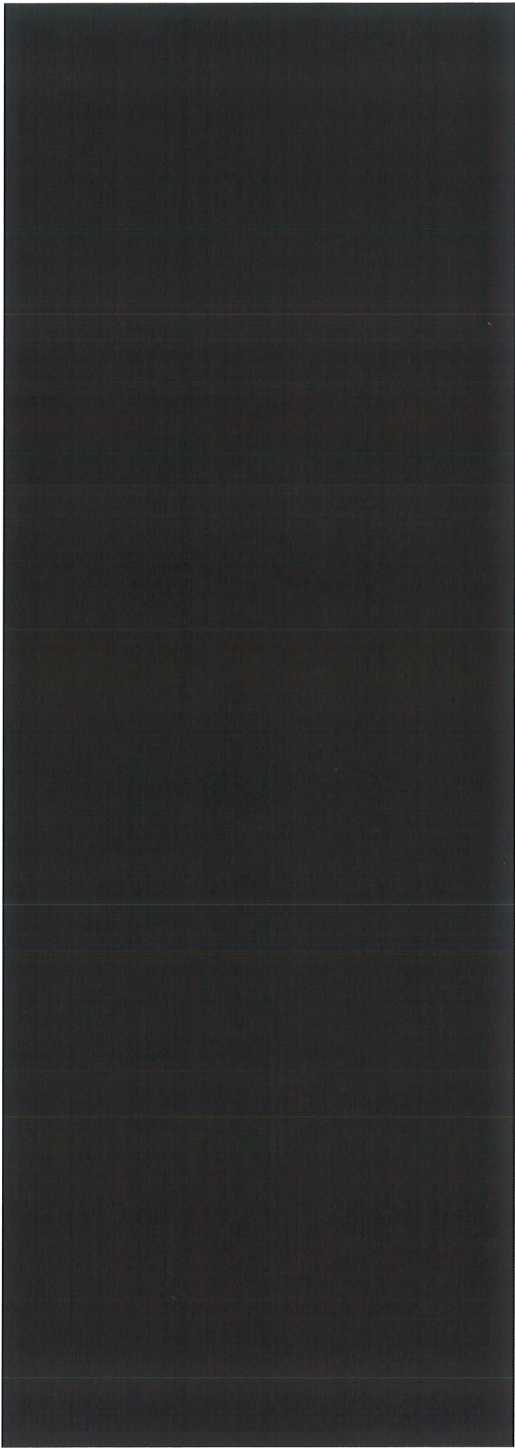
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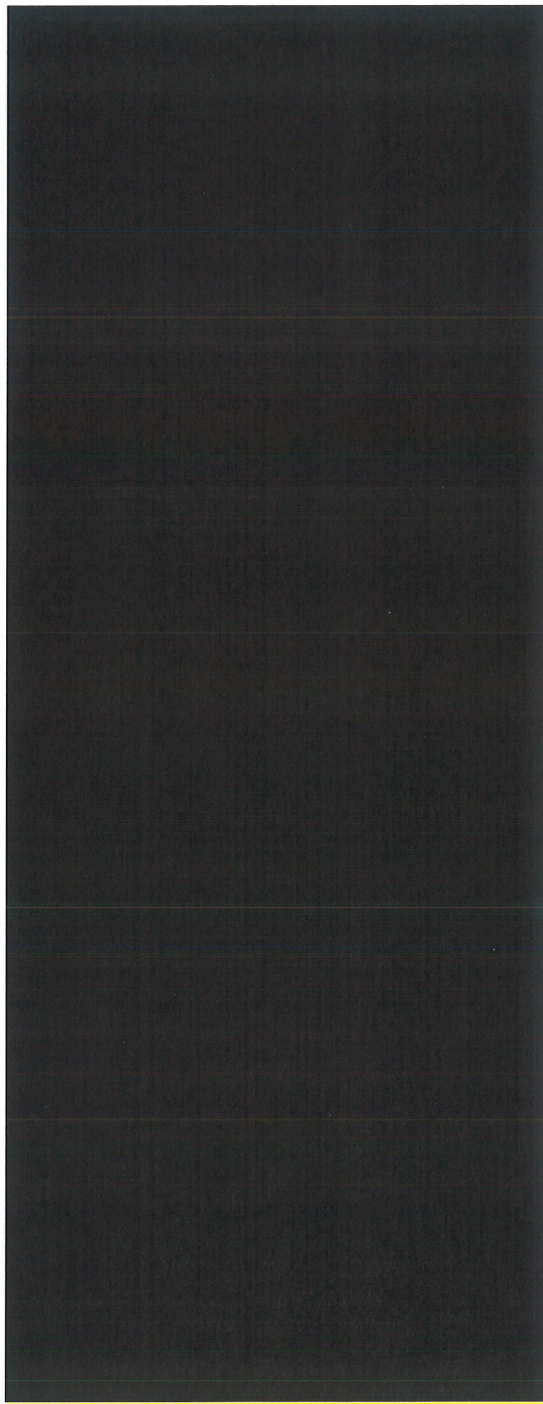


1 **E.2 Scarcity Premium (Capacity Price) Results**

2 Exhibit ICF E-4, ICF E-5 and ICF E-6 show ICF's scarcity premium (i.e., capacity price)
3 forecasts for the OGE control area under the Base, high and low gas price cases respectively. All
4 results are shown in 2015\$. The period of analysis covered 30 years from 2016 to 2045.

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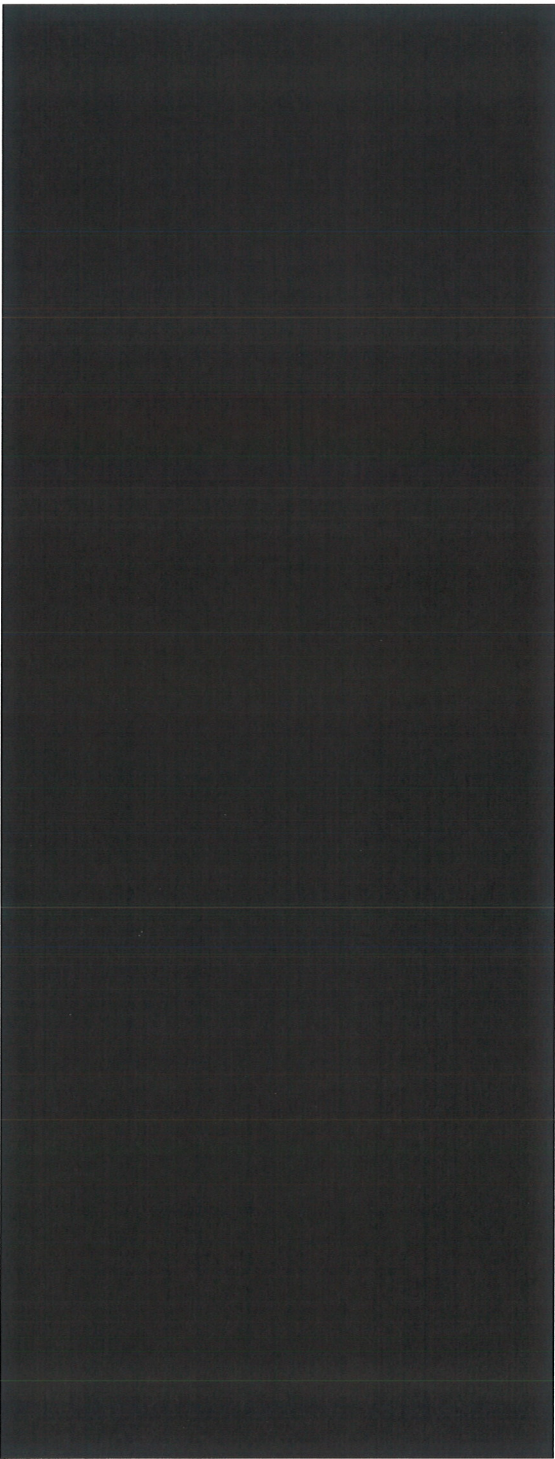
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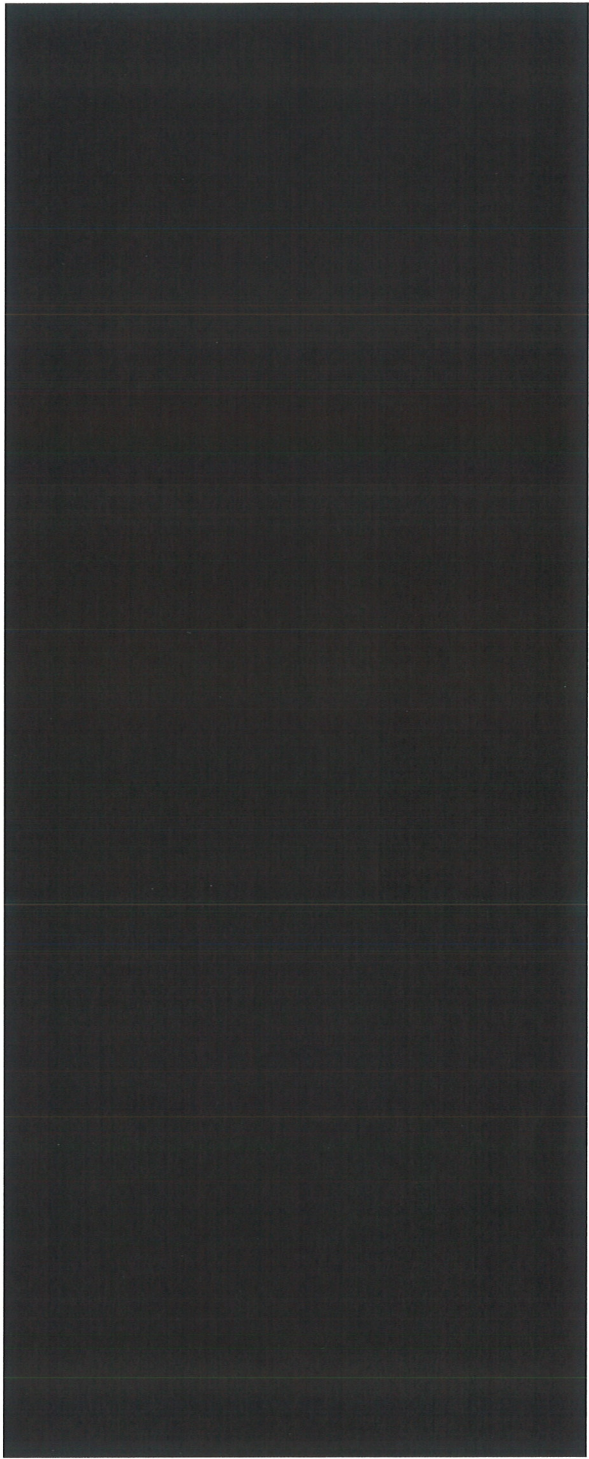
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