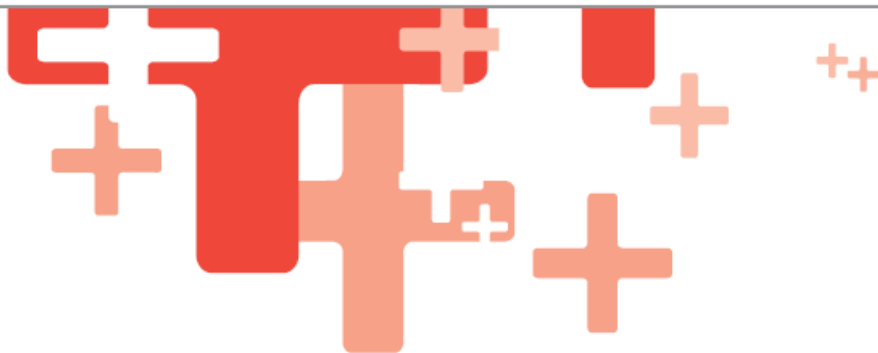


OKLAHOMA GAS AND ELECTRIC COMPANY

INTEGRATED RESOURCE PLAN

Prepared 2015 by: Oklahoma Gas and Electric Company



OG&E[®]

EXECUTIVE SUMMARY

OG&E submits its Integrated Resource Plan (“IRP”) in compliance with the IRP requirements that have been established pursuant to the Oklahoma Corporation Commission’s (“OCC”) Electric Utility Rules OAC 165:35-37. This 2015 IRP reflects updates of certain of the planning assumptions which were utilized in the analysis described in the Company’s 2014 IRP Update. The 2015 assumption updates include the load forecast, existing unit planning capacities, emission control costs, supply resources costs, transmission projects, fuel price forecasts and planning capacity margin.

In August 2014, OG&E submitted an IRP to address a material change in planning assumptions addressing specific environmental rules with which OG&E must now comply. Those rules include the United States Environmental Protection Agency (“EPA”) Mercury and Air Toxics Standards Rule (“MATS”), the Oklahoma Regional Haze State Implementation Plan (“SIP”) and the EPA’s Regional Haze Federal Implementation Plan (“FIP”). In the 2014 IRP, OG&E addressed which of several alternatives met the requirements of the EPA FIP and MATS obligations, while serving the best long-term interests of our customers in light of future environmental uncertainties. OG&E identified the best environmental compliance alternative based on a calculation of the lowest, reasonable cost to our customers.

The Company has concluded that the updated planning assumptions in this IRP do not materially impact the analysis and action plan identified in the 2014 IRP Update. The “Scrub/Convert” alternative selected in the 2014 update continues to be the best approach for OG&E’s customers, meeting the EPA mandates at the lowest reasonable cost with due consideration to the uncertainty associated with fuel and carbon price expectations. The “Scrub/Convert” alternative involves the installation of dry scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. It remains the lowest cost alternative in the base case and provides a compromise between the “Scrub” alternative with its CO₂ risk and the “Convert” alternative that exposes customers to high natural gas price risk.

Similarly, after considering the appropriate updates, OG&E continues to believe the retirement of the Mustang steam units in late 2017 and replacement with new, efficient combustion turbines (“CTs”) at the existing Mustang site in 2018 and 2019 is in the best interest of our customers. The initial Mustang unit was built in 1950 and each of the Mustang units have already operated well beyond the retirement age of nearly all units in the United States of similar type and size. A significant failure could render the existing units unavailable to meet planning capacity margin requirements for an extended period of time and/or indefinitely.

In addition, OG&E’s choice of the existing Mustang site as the location for new CTs remains valid for the reasons articulated in the 2014 IRP Update. Since it is close to OG&E’s largest load center, the site provides valuable reliability support and voltage control functions. The site is also beneficial because of existing infrastructure such as

secure property, electric transmission and interconnection facilities, a gas pipeline connection, roads, buildings, water lines, water rights to support operation and maintenance of the plant, an existing workforce and community support. In addition, retiring and replacing the capacity of the Mustang steam units on the aforementioned schedule allows OG&E to take advantage of existing site-specific environmental permits. Delaying replacement of these units will limit or eliminate OG&E's ability to permit the capacity that OG&E needs to meet SPP planning capacity margin requirements at the Mustang site. The addition of new CTs at Mustang will also enhance the development of additional wind in Oklahoma.

OG&E believes this 2015 IRP and the associated Action Plan reflects a continued focus on a number of key objectives:

- Places the Company in compliance with Regional Haze and MATS requirements within the prescribed deadlines.
- Provides a balanced approach of cost and risk while preserving fuel diversity and ensures SPP capacity requirements are met.
- Preserves the strategic Mustang site, enhances the availability of Oklahoma wind, preserves jobs, and provides reliability benefits in the SPP IM.
- Provides the best opportunity to hold down customers' costs in a variety of future circumstances.

As contemplated in the 2014 IRP Update, OG&E has taken steps to monitor market conditions and the feasibility of implementing future generation options.

On May 18, 2015, OG&E issued both a wind RFI and a solar RFI and, by June 21, 2015, received forty six (46) responses that OG&E is in the process of reviewing. OG&E is in the process of analyzing the responses and conducting congestion and market revenue studies. On June 8, 2015, OG&E issued a Request for Information ("RFI") for up to 200 MW of fossil fuel purchase power capacity to be delivered between May 1, 2020 and August 31, 2022. By August, 2015, OG&E has received four responses and is in the process of evaluating such options, including considering whether entering into a short term PPA will allow OG&E to delay the addition of new generation capacity until 2023.

Contents

| | |
|---|----|
| I. Introduction | 5 |
| A. Purpose of the IRP Submittal..... | 5 |
| B. Description of OG&E Service Territory | 5 |
| C. Outline of the Report..... | 5 |
| II. The 2020 Goal, SPP’s Integrated Marketplace, and OG&E’s Environmental Compliance Challenges | 7 |
| A. OG&E’s 2020 Goal Progress | 7 |
| B. SPP’s Integrated Marketplace..... | 9 |
| C. Environmental Compliance Obligations | 10 |
| 1. Compliance with the MATS and Regional Haze Rules..... | 10 |
| 2. Future Environmental Compliance Risks | 13 |
| III. IRP Objectives and Process..... | 17 |
| A. IRP Objectives | 17 |
| B. IRP Process | 18 |
| IV. Assumptions and Inputs..... | 19 |
| A. 2015 Load Forecast and Demand Side Resources | 19 |
| 1. Load Forecast – Energy and Peak Demand | 19 |
| 2. Demand Side Management..... | 20 |
| B. Supply-Side Resources | 23 |
| 1. Existing Resources..... | 23 |
| 2. Retirement Assumptions | 25 |
| 3. Emission Control Technologies | 27 |
| 4. New Build Supply-Side Resources..... | 28 |
| 5. Transmission to Connect New Supply-Side Resources | 31 |
| C. New Transmission Facilities | 31 |
| D. Fuel and CO ₂ Assumptions..... | 34 |
| E. Integrated Marketplace Prices | 34 |
| 1. Market Price Scenarios | 35 |
| 2. Market Price Sensitivities | 36 |
| V. Resource Planning Modeling and Analysis..... | 38 |
| A. OG&E’s Capacity Planning Obligation | 38 |
| B. Environmental Compliance Analysis..... | 39 |

| | |
|---|----|
| 1. Development of Portfolios | 39 |
| 2. Portfolio Modeling Analysis | 41 |
| 3. Lowest Reasonable Cost Plan | 47 |
| C. Wind Energy Analysis | 47 |
| D. Central Solar Analysis | 48 |
| E. Conclusions from Resource Planning Analysis | 49 |
| VI. Resource strategy and action plan..... | 50 |
| A. Environmental Controls..... | 50 |
| 1. Activated Carbon Injection | 50 |
| 2. Low NO _x Burners..... | 50 |
| 3. Dry Scrubbers at Sooner | 50 |
| 4. Convert Muskogee 4 & 5 to Natural Gas | 51 |
| B. Mustang Unit Retirement and Replacement Units | 51 |
| C. Demand Side Management Plan | 51 |
| D. Future Generation Options | 51 |
| VII. Schedules | 52 |
| Schedule A – Electric Demand and Energy Forecast..... | 52 |
| Schedule B – Existing Resources | 53 |
| Schedule C – Transmission Capability and Needs..... | 54 |
| Schedule D – Needs Assessment | 54 |
| Schedule E – Resource Options | 55 |
| Schedule F – Fuel Procurement and Risk Management Plan..... | 55 |
| Schedule G – Action Plan | 55 |
| Schedule H – Requests for Proposals..... | 56 |
| Schedule I – Modeling Methodology and Assumptions | 57 |
| Schedule J – Transmission System Adequacy | 58 |
| Schedule K – Resource Plan Assessment | 60 |
| Schedule L – Proposed Resource Plan Analysis | 61 |
| Schedule M - Physical and Financial Hedging | 61 |
| VIII. Appendices | 63 |

List of Tables

| | |
|--|----|
| TABLE 1: 2020 GOAL ACTIONS TO DATE (MW)..... | 7 |
| TABLE 2: ENVIRONMENTAL EQUIPMENT INSTALLATION PLANS | 13 |
| TABLE 3: OG&E ENERGY SALES FORECAST (GWH) | 20 |
| TABLE 4: OG&E PEAK DEMAND FORECAST (MW) | 20 |
| TABLE 5: FORECASTED ENERGY REDUCTION FROM DSM (GWH) | 23 |
| TABLE 6: FORECASTED PEAK DEMAND REDUCTION FROM DSM (MW)..... | 23 |
| TABLE 7: OG&E EXISTING GENERATION RESOURCES – 2016 PEAK PLANNING CAPACITY* | 24 |
| TABLE 8: EMISSION CONTROL TECHNOLOGIES (2015 DOLLARS) | 27 |
| TABLE 9: NEW RESOURCE SCREENING REQUIREMENTS (2015 DOLLARS)..... | 28 |
| TABLE 10: CENTRAL SOLAR PHOTOVOLTAIC (2015 DOLLARS) | 30 |
| TABLE 11: NEW SUPPLY SIDE RESOURCES (2015 DOLLARS) | 30 |
| TABLE 12: ESTIMATED EXPANSION COST AT McCLAIN SUBSTATION | 31 |
| TABLE 13: MAJOR 345 kV TRANSMISSION PROJECTS | 33 |
| TABLE 14: CO ₂ PRICE FORECAST (\$/TON) | 34 |
| TABLE 15: PLANNING CAPACITY MARGIN (MW UNLESS NOTED)..... | 38 |
| TABLE 16: EXPANSION PLANS..... | 40 |
| TABLE 17: MARKET SCENARIO 30-YEAR NPVCC VALUES (2014 \$BILLIONS)..... | 43 |
| TABLE 18: SENSITIVITY 30-YEAR NPVCC VALUES (2014 \$BILLIONS) | 45 |

List of Figures

| | |
|--|----|
| FIGURE 1: OG&E SERVICE AREA | 5 |
| FIGURE 2: NAMEPLATE CAPACITY AND GENERATION MIX CHANGES..... | 8 |
| FIGURE 3: INTEGRATED RESOURCE PLANNING SEVEN STEP PROCESS | 18 |
| FIGURE 4: ASSUMED GAS-FIRED STEAM UNIT RETIREMENTS..... | 27 |
| FIGURE 5: EIA FUEL FORECAST (ANNUAL AVERAGE)..... | 34 |
| FIGURE 6: SPP MARKET SCENARIOS (ANNUAL AVERAGE \$/MWH) | 35 |
| FIGURE 7: MARKET PRICES FOR SENSITIVITY ANALYSIS (ANNUAL AVERAGE \$/MWH) | 36 |
| FIGURE 8: REGIONAL HAZE COMPLIANCE ALTERNATIVES | 39 |
| FIGURE 9: PORTFOLIO DEVELOPMENT | 41 |
| FIGURE 10: CUSTOMER COST COMPONENTS | 41 |
| FIGURE 11: COMPLIANCE ALTERNATIVE AND EXPANSION PLAN COMPARISON | 42 |
| FIGURE 12: COST COMPONENT COMPARISON FOR SELECT COMPLIANCE ALTERNATIVES | 42 |
| FIGURE 13: COMPLIANCE ALTERNATIVES AND MARKET SCENARIO COMBINATIONS..... | 43 |
| FIGURE 14: CUSTOMERS PRODUCTION COST IN BASE CASE MARKET SCENARIO | 44 |
| FIGURE 15: CUSTOMERS PRODUCTION COST IN HIGH CONVERSION MARKET SCENARIO | 44 |
| FIGURE 16: SENSITIVITY DEVELOPMENT | 45 |
| FIGURE 17: SENSITIVITY ANALYSIS NPVCC (2014 \$BILLIONS)..... | 46 |
| FIGURE 18: POTENTIAL REVENUE AND COST (2014 \$MILLIONS) | 49 |
| FIGURE 19: ACTION PLAN TIMELINE | 50 |

List of Acronyms

| Acronym | Phrase Represented | Reference |
|--------------|---|------------|
| ACI | Activated Carbon Injection | Technology |
| APSC | Arkansas Public Service Commission | Agency |
| BART | Best Available Retrofit Technology | Technology |
| CAA | Clean Air Act | EPA |
| CC | Combined Cycle electricity generating unit | Technology |
| CCR | Coal Combustion Residuals Rule | EPA |
| CSAPR | Cross-State Air Pollution Rule | EPA |
| CT | Combustion Turbine electricity generating unit | Technology |
| DG | Distributed Generation | Technology |
| DSM | Demand Side Management | Industry |
| EE | Energy Efficiency | OG&E |
| EHV | Extra High Voltage | Technology |
| EIA | Energy Information Administration | Agency |
| EIS | Energy Imbalance Services | SPP |
| EPA | Environmental Protection Agency | Agency |
| FERC | Federal Energy Regulatory Commission | Agency |
| FIP | Federal Implementation Plan | EPA |
| HPILS | High Priority Incremental Load Study | SPP |
| IM | Integrated Marketplace | SPP |
| IRP | Integrated Resource Plan | Industry |
| ITP | Integrated Transmission Planning | SPP |
| ITP10 | Integrated Transmission Planning 10 Year Assessment | SPP |
| ITP20 | Integrated Transmission Planning 20 Year Assessment | SPP |
| ITPNT | Integrated Transmission Planning Near-Term Assessment | SPP |
| IVVC | Integrated Volt Var Control | OG&E |
| LMP | Locational Marginal Price | SPP |
| LRR | Load Reduction Rider | OG&E |
| MATS | Mercury and Air Toxics Standards Rule | EPA |
| NAAQS | National Ambient Air Quality Standards | EPA |
| NERC | North American Electric Reliability Corporation | Agency |
| NPV | Net Present Value | General |
| NPVCC | Net Present Value of Customer Cost | OG&E |
| OCC | Oklahoma Corporation Commission | Agency |
| ROFR | Right of First Refusal | SPP |
| PPA | Purchase Power Agreement | Industry |
| PV | Photovoltaic | Technology |
| RFI | Request for Information | General |
| RFP | Request for Proposals | General |
| SIP | State Implementation Plan | OK |
| SPP | Southwest Power Pool | SPP |
| STEP | SPP Transmission Expansion Plan | SPP |
| TBD | To Be Determined | SPP |
| TOSP | Transmission Owner Selection Process | SPP |

I. INTRODUCTION

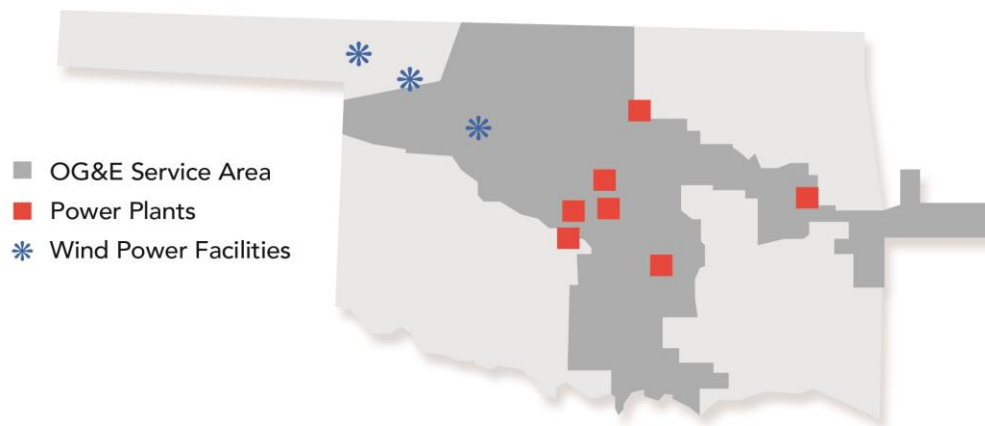
A. Purpose of the IRP Submittal

OG&E submits this IRP pursuant to the OCC Electric Utility Rules fulfilling the triennial requirement stated in OAC 165:35-37-4(a). In conjunction with the fundamental review of OG&E's short term and long term resource needs contemplated by the Commission rules, this submittal addresses in particular compliance with EPA's Mercury and Air Toxics Standards Rule ("MATS") and with the Regional Haze requirements of the Clean Air Act ("CAA"), including certain requirements of Oklahoma's State Implementation Plan ("SIP") and implementation of the Federal Implementation Plan ("FIP") promulgated by the EPA.

B. Description of OG&E Service Territory

OG&E serves more than 800,000 retail customers in Oklahoma and western Arkansas. The service territory covers approximately 30,000 square miles, includes 268 communities and surrounding areas, and has a population of approximately 2 million. OG&E serves Oklahoma City, which is the largest city in Oklahoma, as well as Ft. Smith, Arkansas. Of the 268 communities served by OG&E, 242 are in Oklahoma, and 26 are in Arkansas. OG&E's retail service area is shown in Figure 1.

Figure 1: OG&E Service Area



C. Outline of the Report

This IRP Report and Appendices comply with OCC Electric Utility Rules and APSC Resource Planning Guidelines for Electric Utilities. Section II describes the SPP IM and OG&E's environmental compliance obligations, and provides context as to how each of these developments relates to OG&E's 2020 Goal. Section III presents the IRP

objectives and process. Section IV offers the demand and energy forecast and modeling assumptions and inputs used in the analysis. Section V explains the analysis methodology and results. Section VI summarizes the five-year action plan. Section VII concludes the report with the following schedules as required by Oklahoma Corporation Commission rule OAC 165:35-37-4(c):

- A. Electric demand and energy forecast
- B. Forecast of capacity and energy contributions from existing and committed supply- and demand-side resources
- C. Description of transmission capabilities and needs covering the forecast period
- D. Assessment of the need for additional resources
- E. Description of the supply, demand-side and transmission options available to the utility to address the identified needs
- F. Fuel procurement plan, purchased power procurement plan, and risk management plan
- G. Action plan identifying the near-term (i.e., across the first five (5) years) actions
- H. Proposed RFP(s) documentation, and evaluation
- I. Technical appendix for the data, assumptions and descriptions of models
- J. Description and analysis of the adequacy of its existing transmission system
- K. Assessment of the need for additional resources to meet reliability, cost and price, environmental or other criteria
- L. An analysis of the utility's proposed resource plan
- M. Description and analysis of the utility's consideration of physical and financial hedging to determine the utility's ability to mitigate price volatility

The report also includes several Appendices. Appendix A presents OG&E's 2015 Load Forecast. Appendix B presents the annual customer costs for the resource portfolios discussed in the plan. Appendix C presents the annual emissions for the resource portfolios. Appendix D presents the technical conference minutes for Oklahoma.

II. THE 2020 GOAL, SPP'S INTEGRATED MARKETPLACE, AND OG&E'S ENVIRONMENTAL COMPLIANCE CHALLENGES

This section reviews the actions that OG&E has taken to reconfigure its portfolio since 2007, SPP's new Integrated Marketplace ("IM") and its impact on OG&E's resource planning process, and the environmental challenges that must be addressed by OG&E.

The 2020 Goal and OG&E's prior actions to meet that goal provide the foundation for this IRP. OG&E's customers are already using electricity more efficiently and shifting their usage from peak to non-peak hours. OG&E will continue investments and programs that achieve further gains on the customer side of the meter. The generation fleet also is more efficient and produces far fewer emissions than it did in 2007. Through the additions of wind energy, OG&E's generation portfolio is more diverse than it has ever been.

A. OG&E's 2020 Goal Progress

The 2020 Goal established the objective to defer the addition of new, incremental fossil fuel capacity until at least 2020 through a combination of wind energy, new energy efficiency programs, smart grid-enabled demand response, and termination of wholesale contracts and by doing so, defer the construction of new incremental fossil fuel generation until 2020 despite the retirement of aging and less efficient generation. The specific changes undertaken by OG&E since the goal was announced in the fall of 2007, including demand-side management ("DSM") actions to date are presented in Table 1.

Table 1: 2020 Goal Actions to Date (MW)

| Year | Solar | Wind | DSM | Wholesale |
|-----------------------------|---------------|--------------------------------------|---------------|---------------|
| 2008 | | | 2 | 18 |
| 2009 | | OU Spirit – 101 | 13 | |
| 2010 | | Keenan – 152 | 12 | 5 |
| 2011 | | Taloga – 130 Crossroads – 228 | 22 | |
| 2012 | | Cowboy – 60 | 118 | 14 |
| 2013 | | | 99 | 50 |
| 2014 | | | 102 | 10 |
| 2015 | Mustang - 2.5 | | | 229 |
| 2020 Goal Total | 2.5 MW | 671 MW | 368 MW | 326 MW |
| Prior Wind Additions | | Sooner Wind – 50 Centennial – 120 | | |
| Total | 2.5 MW | 841 MW | 368 MW | 326 MW |

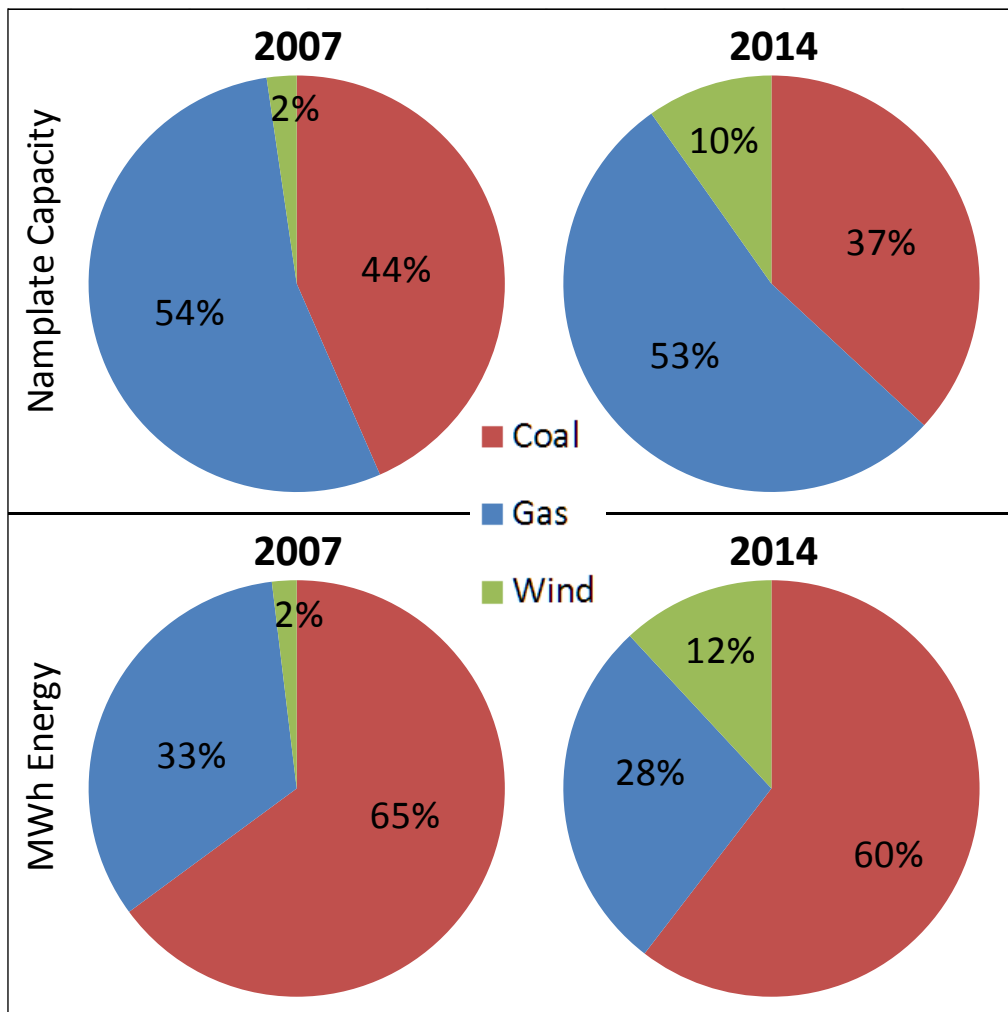
As shown in Table 1, OG&E added 671 MW of wind generation over this period bringing OG&E's total nameplate wind capacity to 841 MW. In 2015, OG&E added 2.5 MW of

solar generation at the existing Mustang power plant site. Load reduction from demand-side resources increased by 368 MW since 2007 and as of July 2015 OG&E has terminated 326 MW of wholesale contracts over this period completing its exit from the wholesale market and further offsetting the amount of capacity that OG&E would otherwise need to meet its SPP planning capacity margin requirements.

In addition to the actions taken to support the 2020 Goal, OG&E also retired several units over this period without replacement: four circa-1965 combustion turbines with a total capacity of 56 MW at Enid, a 10 MW CT at Woodward, and a 171 MW gas steam plant at Muskogee. Continued operation of the Enid and Woodward CTs, as discussed in the 2012 IRP, would have required the installation of Selective Catalytic Reduction technology to bring NOx emissions within required limits. In 2015, OG&E will retire the 16 MW Seminole 1 GT unit and the 51 MW Mustang 1 unit.

These actions have changed OG&E’s capacity and generation mix as shown in Figure 2. Wind capacity represents nameplate capacity and does not represent planning capacity margin.

Figure 2: Nameplate Capacity and Generation Mix Changes



B. SPP's Integrated Marketplace

The SPP IM began operations March 1, 2014. The IM is the latest and most complex incremental step in SPP's evolutionary approach to adding market functionality. The collective components of the IM improve the efficiency of the development and operation of the electricity system across the SPP, enhance the ability for both buyers and sellers to hedge risk and enhance reliability across the SPP footprint through a regional balancing of supply and demand,

The IM accomplishes its various objectives through the following capabilities:

- (1) a Day-Ahead Market with Transmission Congestion Rights;
- (2) a Reliability Unit Commitment process;
- (3) a Real-Time Balancing Market that supplants SPP's EIS Market;
- (4) a price-driven Operating Reserve Market; and
- (5) a single SPP-wide Balancing Authority.

The region-wide efficiencies and services enabled by the SPP IM are designed to produce savings for SPP members and their customers. From March 2014 through June 2015, OG&E's participation in the SPP IM resulted in approximately \$72 million in savings to OG&E's customers.

The IM does not operate a capacity market or conduct an annual regional process for load serving entities to obtain incremental capacity, as is the case in certain other regions. OG&E continues to have responsibility for ensuring that it has planning capacity sufficient to serve its peak load requirements and a planning capacity margin. It must meet these capacity obligations through OG&E-owned generation or contracts for capacity.

OG&E's minimum capacity planning reserve margin continues to be established pursuant to Section 4.3.5 of the SPP Criteria as follows:

Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities.

Thus, OG&E is required to maintain capacity levels that allow for a minimum of 12% margin between capacity and demand. This calculation is explained in Section 2.1 of the SPP Criteria as represented in the following equation:

$$\text{Capacity Margin \%} = \frac{(\text{Total Net Capability}) - (\text{Net On System Demand})}{(\text{Total Net Capability})}$$

This obligation is identical to the capacity planning assumption that was reflected in OG&E's previous IRPs. OG&E and all other Load Serving Entities now obtain all of their energy through the IM and pay hourly locational marginal prices established by the

market, rather than relying on owned or contracted assets for energy. Also, OG&E sells all of its energy generated by its assets, including contracted assets, into the IM so the IM has a direct impact on (1) the degree to which OG&E's generation resources are called upon to provide electricity and (2) on the revenues that result from SPP market compensation mechanisms that establish hourly locational prices paid to each generation source.

As a result, in order to evaluate new generation resources in the IRP, it is necessary to forecast the market prices for the region that will apply to electricity generated by OG&E units and to purchases from the market to serve OG&E's load. As described in Section IV E, OG&E utilizes Ventyx PROMOD IV, an electric market simulation tool which incorporates generating unit operating characteristics, transmission grid topology and constraints, to estimate future energy prices in the SPP IM. Further, market conditions such as availability of diverse generation resources, fuel pricing and emission costs impact market pricing and this is reflected in the design of scenario analyses that capture the uncertainty in these areas.

C. Environmental Compliance Obligations

The electricity production activities of OG&E are subject to a stringent, complex and interrelated set of existing Federal, state and local laws and regulations, especially those governing environmental protection. These laws and regulations can restrict or impact OG&E's business activities in many ways including requiring remedial action to mitigate certain emissions and discharges, restricting the way OG&E handles or disposes of its wastes, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of emission control equipment.

Existing and potential environmental obligations can have a major impact on OG&E's resource plan and have been examined in several prior IRP submittals. OG&E's 2015 IRP is designed to meet the existing environmental obligations while at the same time also considering the potential of future environmental regulations, even though certain of these rules, including the potential regulation of greenhouse gas emissions, are not settled.

1. Compliance with the MATS and Regional Haze Rules

The focus of OG&E's existing environmental obligations is on the emissions of SO₂, NO_x, and certain hazardous air pollutants. Rules that are currently applicable are the MATS and Regional Haze rules, which combine to impact OG&E's coal and certain gas steam units.

a) Mercury and Air Toxics Standards Rule

The final MATS rule, published on February 16, 2012 and effective April 16, 2012, includes numerical standards for particulate matter (as a surrogate for metals), hydrogen chloride (acid gases) and mercury emissions from coal-fired boilers. The

regulations also include work practices for dioxins and furans. Compliance is required by April 16, 2015 unless extended for one year by the state environmental regulatory agency. OG&E requested and has received a one-year extension for compliance to April 16, 2016 from the Oklahoma Department of Environmental Quality.

OG&E plans to comply with MATS by installing activated carbon injection (“ACI”) at five coal-fired units. The cost of installing ACI on all five of OG&E’s coal units is estimated to be \$24 million. OG&E does not believe any retrofits are necessary at its five coal-fired generating units to comply with the particulate matter and acid gas emission limits.

Because of the relatively low cost of the ACI systems and the three-year difference in the compliance timeframes for MATS and Regional Haze, OG&E determined that installing ACI at the five coal-fired units was the least-cost choice irrespective of a subsequent decision with respect to its coal units under the Regional Haze compliance plan. In order to comply with the April 16, 2016 MATS compliance deadline, OG&E has begun the engineering and design process to support ACI installation and is currently scheduled to finish the construction and installation by January 2016.

The final MATS rule was appealed by several parties. After withstanding judicial scrutiny at the District of Columbia Circuit Court of Appeals, the MATS rule was challenged at the U.S. Supreme Court. On June 29, 2015, the U.S. Supreme Court remanded the MATS rule to the DC Circuit Court for further proceedings, finding that the EPA should have considered the compliance costs imposed on utilities at the first stage of the Agency’s regulatory analysis. The MATS rule currently remains in effect and OG&E is still required to meet the April 2016 compliance deadline unless the D.C. Circuit vacates the rule or grants some other relief from the compliance mandate.

b) Regional Haze and the Federal Implementation Plan

On July 6, 2005, the EPA published final amendments to its 1999 regional haze rule. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. These regulations are intended to protect visibility in certain national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains is the only area covered under the regulation. However, Oklahoma's impact on national parks in other states must also be evaluated.

As required by the Federal regional haze rule, the State of Oklahoma evaluated the installation of Best Available Retrofit Technology (“BART”) to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. Certain units at the Horseshoe Lake, Seminole, Muskogee and Sooner generating stations were evaluated for BART. On February 17, 2010, Oklahoma submitted its SIP to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The Oklahoma SIP included requirements for reducing emissions of NO_x and SO₂ from OG&E's seven BART-eligible units: Seminole

Units 1, 2 & 3, Muskogee Units 4 & 5, and Sooner Units 1 & 2.¹ The SIP also included an approved waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP was subject to the EPA's review and approval.

On December 28, 2011, the EPA rejected portions of the Oklahoma SIP and published a FIP related to Regional Haze SO₂ emission requirements. While the EPA accepted Oklahoma's BART determination for NO_x in the SIP, it rejected the SO₂ BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. In its place, the EPA implemented its FIP requiring that OG&E meet an SO₂ emission rate of 0.06 pounds per MMBtu within five years. OG&E can meet the proposed standard by either installing and operating Flue Gas Desulfurization equipment (scrubbers) or fuel switching to natural gas at the four affected units.

The State of Oklahoma and OG&E challenged the FIP at the 10th Circuit Court of Appeals and the 10th Circuit Court of Appeals upheld the EPA's rejection of the SO₂ emission portion of Oklahoma SIP and the EPA's implementation of the FIP in July 2013. Review by the United States Supreme Court of the 10th Circuit's decision was sought and denied on May 27, 2014, causing the 10th Circuit's decision to become final. One positive of these various legal proceedings is that OG&E received a stay of the FIP, which extended the compliance deadline for the SO₂ portion of the FIP.² The Court's stay was lifted on May 30, 2014 making the FIP compliance deadline January 4, 2019.

As explained in Section V, OG&E has modeled several scenarios that would meet the Regional Haze FIP SO₂ emission limits, including scrubbing all four affected units, converting or replacing all such units to natural gas and a combination of scrubbing and conversion/replacement.

c) Initial Actions to Comply with the MATS and Regional Haze Rules

OG&E has already taken certain actions to address these existing requirements by installing emission control equipment at eight of its units. Specifically, OG&E is installing low NO_x burners at seven units (Muskogee 4 & 5, Sooner 1 & 2, and Seminole 1, 2 & 3) and ACI at its five coal-fired units. These investments are shown in Table 2.

¹ Muskogee Unit 6 was not in existence prior to August 7, 1977; therefore, Unit 6 is not a BART-eligible source. Unit 6 commenced commercial operation in mid-1984.

² The compliance deadline for the NO_x portion of the Oklahoma SIP remains January 2017, as this portion of the Oklahoma SIP was approved by the EPA and was not subject to the stays granted by the 10th Circuit while the FIP was being challenged.

Table 2: Environmental Equipment Installation Plans

| Equipment | Begin Construction | Completion | Approximate Investment Cost* |
|--|--------------------|------------|------------------------------|
| Low NO_x Burners on 7 Units | Feb-13 | Jan-17 | \$103 million |
| Activated Carbon Injection on 5 Units | Apr-15 | Apr-16 | \$23 million |

**Includes both past and future investment.*

2. Future Environmental Compliance Risks

Environmental regulations are generally expected to become ever more stringent. Many of the new and more stringent requirements are focused on coal-fired generation. However, there are also numerous examples of environmental rules that took many years to finalize and changed materially from the initial proposal to the final rule. If OG&E had acted on some of these proposed rules before they were finalized; it could have spent significant capital and on-going operations and maintenance costs that were never ultimately required and imposed unnecessary costs on its customers. This is especially important as emerging federal rules often take many years to reach an unappealable end where more certainty on the implementation and timelines can be determined.

One recent example of this is the recently promulgated Cooling Water Intake Structures rule under Section 316(b) of the federal Clean Water Act. It involved an effort to protect fish populations from cooling water intake structures at electric generating facilities. This was not the first attempt that EPA has made to promulgate these rules. In fact, this rule has been re-proposed and finalized three separate times over the past forty years. Based on one of the older iterations of the proposed rule, OG&E had previously estimated that the potential cost of compliance could be as much as \$7.5 million per unit to install cooling towers at seven OG&E coal and natural gas units. However, the 2004 rule and its requirements never went into effect and the third and most current version of the rule, which was finalized in August 2014, will not require those very high costs. OG&E is confident that cooling towers (the most expensive option for complying with the rule) will not be required nor will other equally expensive measures be needed.

EPA's Coal Combustion Residuals (CCR) rulemaking is another good example of this dynamic. In 2008, EPA embarked on a rulemaking for disposal and use of CCR. A proposed rule was released in June 2010 which contained three options for the regulation of coal ash. The most stringent option would have treated CCRs as a hazardous waste for the first time. Had OG&E acted on the proposed rule and assumed that coal ash would have been regulated as a hazardous waste, OG&E would have potentially incurred hundreds of millions in costs attributable to reengineering and rebuilding the coal ash handling system at both Sooner and Muskogee for compliance. None of these costs are required under the final version of the rule which was finalized in April 2015 and goes into effect in October 2015.

Therefore, OG&E closely watches proposed rules and how they change over time.

OG&E believes that the 2015 IRP reflects planning decisions which position the Company well to comply with the proposed rules, if they are finalized and survive judicial review. More information on pending federal rules is discussed below.

a) Cross-State Air Pollution Rule (“CSAPR”)

On August 8, 2011, the EPA published CSAPR to replace the former Clean Air Interstate Rule that was remanded by a federal court as a result of legal challenges. The final rule impacted 27 states, but not the State of Oklahoma. On December 27, 2011, the EPA published a supplemental rule (“Supplemental Rule”), which would make five additional states, including Oklahoma, subject to CSAPR for NO_x emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E would have been required to reduce ozone-season NO_x emissions from its electrical generating units within the state beginning in 2012. Both rules were challenged in court by numerous states and utilities. On December 30, 2011, the D.C. Circuit Court of Appeals stayed the applicability of both rules. On August 21, 2012, the D.C. Circuit Court vacated CSAPR and ordered the EPA to promulgate a replacement rule. The Supplemental Rule was not vacated with the original rule but remained stayed at the D.C. Circuit Court of Appeals pending briefing of the merits. After further appeal of the original CSAPR to the U.S. Supreme Court, the Supreme Court, on April 29, 2014, reversed and remanded the case to the D.C. Circuit Court to resolve a number of outstanding technical issues. The D.C. Circuit then lifted the stay, and EPA implemented the 2012 emissions requirements in 2015, with which OG&E has begun complying. Despite the lifting of the stay, the D.C. Circuit has remanded certain portions of the rule back to the EPA and the Supplemental Rule continues to be challenged. The low NO_x combustion equipment being installed for regional haze also will help meet the CSAPR requirements contained in the Supplemental Rule.

b) Greenhouse Gas Regulations

On August 3, 2015, the EPA issued its final Clean Power Plan rules that establish carbon pollution standards for power plants, called CO₂ emission performance rates. The EPA expects each state to develop implementation plans for power plants in its state to meet the individual state targets established in the Clean Power Plan. The EPA has given states the option to develop compliance plans for annual rate-based reductions (lb/MWh) or mass-based tonnage limits for CO₂. The 2030 rate-based reduction requirement for all existing generating units in Oklahoma has decreased from a proposed 43 percent reduction to 32 percent in the final rule. The mass-based approach for existing units calls for a 24 percent reduction by 2030 in Oklahoma. The state plans are due in September 2016, subject to potential extensions of up to two years for final plan submission. The compliance period begins in 2022, and emission reductions will be phased in to 2030. The EPA also proposed a federal compliance plan to implement the Clean Power Plan in the event that an approvable state plan is not submitted to the EPA. OG&E is evaluating the Clean Power Plan rules and has not reached any final conclusions.

c) National Ambient Air Quality Standards (“NAAQS”)

The EPA is required to set NAAQS designed to be protective of human health and the environment for six specific pollutants. The Clean Air Act requires the EPA to review each NAAQS every five years. As a result of these reviews, the EPA periodically has taken action to adopt more stringent NAAQS for those pollutants. For example, in 2010, the EPA revised the NAAQS for SO₂ and NO₂, establishing new one-hour standards that are significantly more stringent than the prior standards. If any areas of Oklahoma were to be designated as not attaining the NAAQS for a particular pollutant, OG&E could be required to install additional emission controls on its facilities to help the state achieve attainment with the NAAQS.

To date, no areas of Oklahoma have been designated as non-attainment for NAAQS pollutants that are likely to affect OG&E's operations. However, in recent years, monitored ozone levels in Oklahoma have been close to a NAAQS exceedance level and this assessment is reviewed each year and measured against the standard that is currently in effect.

d) Future Requirements under Regional Haze

When EPA disapproved Oklahoma's BART determinations under Regional Haze for OG&E's four coal-fired units, it said it was taking no action on whether the state had satisfied the reasonable progress requirements of the regional haze provisions in the Clean Air Act. Environmental groups have now sued EPA to force it to take action on this aspect of Oklahoma's regional haze plan. EPA has agreed to issue a final rule by Sep. 4, 2015. The proposed rule does not require any additional emission controls for OG&E.

States are required to develop a SIP for each planning period under the regional haze program. The second planning period commences in 2019. It is not known at this time what requirements, if any, will result from the second planning process and SIP.

e) Endangered Species Act and other Federal Laws

Certain federal laws, including the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unauthorized activities that result in harm to or, harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which OG&E conducts operations, or if additional species in those areas become subject to protection, OG&E's operations and development projects, particularly transmission or wind projects, could be restricted or delayed, or OG&E could be required to implement expensive mitigation measures.

There are a number of species that could potentially be listed under the Act however, it is not known at this time what impacts to OG&E's operations if any will result.

f) New Source Review Litigation

On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. On July 8, 2013, the Department of Justice at the request of the EPA, filed a complaint for declaratory relief against OG&E in U.S District Court for the Western District of Oklahoma (Case No. CIV-13-690-D) alleging that OG&E did not follow the Clean Air Act procedures for projecting emission increases attributable to eight projects that occurred between 2003 and 2006. The Sierra Club has intervened in this proceeding and has asserted claims for declaratory relief that are similar to those requested by the United States. On January 15, 2015, U.S. District Judge Timothy DeGuisti dismissed the complaints filed by EPA and Sierra Club. The Court held that it lacked subject matter jurisdiction over Plaintiffs' claims because Plaintiffs failed to present an actual "case or controversy" as required by Article III of the Constitution. The court also ruled in the alternative that, even if Plaintiffs had presented a case or controversy, it would have nonetheless "decline[d] to exercise jurisdiction." EPA and the Sierra Club did not file an appeal of the Court's ruling.

On August 12, 2013, the Sierra Club filed a separate complaint against OG&E in the U.S District Court for the Eastern District of Oklahoma (Case No. 13-CV-00356) alleging that OG&E's modifications made at Unit 6 of the Muskogee generating plant in 2008 were made without obtaining a prevention of significant deterioration permit and that the plant has exceeded emissions limits for opacity and particulate matter. The Sierra Club seeks a permanent injunction preventing OG&E from operating the Muskogee generating plant. On November 4, 2013, OG&E filed a Motion to Dismiss and on March 4, 2014, the District Court issued an Order dismissing the prevention of significant deterioration claim but allowing the claim relating to opacity and particulate matter emissions to continue. On May 21, 2014, OG&E filed a motion for summary judgment on the remaining opacity and particulate matter claims. At the same time, Sierra Club issued a notice of intent to assert additional opacity and particulate matter claims monitoring and emission limit claims not only against Muskogee 6, but also against Muskogee Units 4 and 5. To obtain the right to appeal this decision, the Sierra Club subsequently withdrew a Notice of Intent to Sue for additional Clean Air Act violations and asked the Eastern District to dismiss its remaining claims with prejudice. On August 27, 2014, the Eastern District dismissed the claims with prejudice. The Sierra Club has filed a Notice of Appeal with the 10th Circuit where oral argument was held on March 18, 2015.

III. IRP OBJECTIVES AND PROCESS

A. IRP Objectives

OG&E strives to develop a lowest reasonable cost resource plan that will allow it to meet its capacity obligations over the 30-year planning horizon at the lowest reasonable cost (as represented by the Net Present Value of Customer Cost or “NPVCC”) with due consideration to the uncertainties attributable to many of the planning assumptions including fuel prices and future environmental regulations. Every generation technology has a differing set of capital costs, O&M costs, and operating characteristics (i.e., the ability to start quickly or run at less than full loading) and these differences are captured in the IRP modeling and reflected in NPVCC calculations.

A primary planning objective that OG&E relies on to address the uncertainties in fuel and emission prices is fuel diversity. Fuel diversity helps to ensure stability in prices and reliability in electric supply, protecting the company and customers from short term contingencies such as fuel unavailability. Natural gas may have limited availability during times of extreme cold weather when well heads can freeze, impacting both the amount of flowing gas and the ability of pipelines to reach carrying capacities. Coal can also have delivery issues which threaten supply, including production problems at the mine site and railroad transportation issues. Catastrophic weather events such as floods, tornado, and weather extremes can impact both fuels.

Fuel diversity also provides protection from fuel price fluctuations caused by market conditions as well as longer term contingencies such as changes in regulatory practices that can drive up the cost of a particular fuel.

OG&E’s goal is to meet SPP’s planning capacity margin requirements with a fuel diverse generation fleet. The sensitivity of portfolio NPVCCs to price forecasts depends to a considerable degree on the nature of the generation mix. For example, the NPVCC of a portfolio that is heavily weighted toward natural gas plants will be relatively insulated from the impact of carbon prices but will swing widely in response to volatility in natural gas prices. Similarly, the NPVCC of a portfolio that is heavily dependent on coal resources will be relatively sensitive to carbon prices and also be at risk should regulation of CO₂ take a less flexible form than a market-based approach. Finally, wind energy provides very little capacity value (and may not generate energy when it is most needed and most valuable).

Thus, while a portfolio with a lower NPVCC is clearly preferred, a portfolio with the lowest NPVCC in any scenario may not represent the lowest reasonable cost portfolio, even if all portfolios are equally reliable. A portfolio that mitigates risks may be preferred to a portfolio that has moderately lower NPVCC but exposes customers to greater risks that actual costs will end up being much higher under a different set of plausible assumptions. The most desirable portfolio can be characterized as a “robust”

portfolio because it will produce an acceptable NPVCC outcome under a wide range of plausible assumptions.

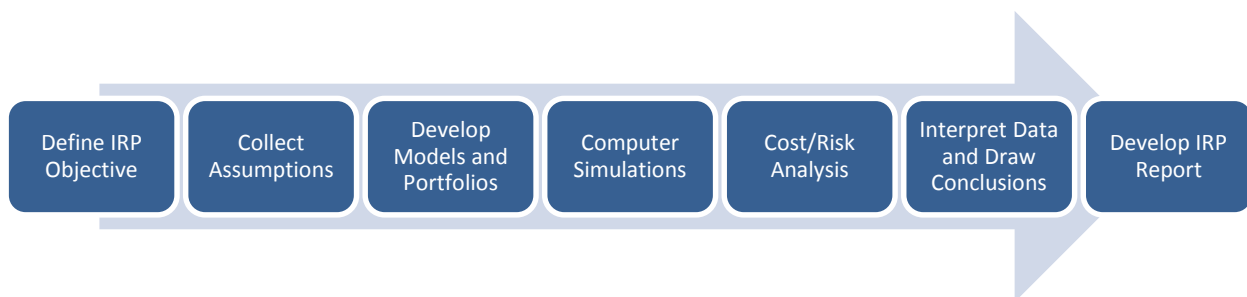
To identify the robust portfolio, OG&E is guided by the following objectives:

- (1) Reliability: satisfy SPP’s planning capacity margin requirements throughout the 30-year planning horizon;
- (2) Compliance with Existing Environmental Rules: satisfy the requirements of MATS and the Regional Haze FIP;
- (3) Expected Cost to Consumers: lowest reasonable NPVCC subject to satisfying other IRP objectives;
- (4) Fuel Diversity: maintain a reasonable balance among natural gas, coal, and wind, and other economically viable renewable resources;
- (5) Operational Flexibility: maintain or increase the ability of OG&E’s portfolio to respond at SPP’s direction to localized reliability issues (through quick-start peaking units, for example);
- (6) Portfolio Age: maintain a reasonable balance of capacity as measured by expected remaining asset life;
- (7) Demand-Side Resources: maximize the reliance on economic demand-side resources;
- (8) Exposure to Fuel and Emissions Prices: consider the sensitivity of NPVCC based on different assumptions regarding fuel and emissions prices;
- (9) Exposure to Future Environmental Regulation: consider the potential that future environmental regulations (particularly regulations intended to address greenhouse gases) may result in costly environmental compliance solutions.

B. IRP Process

The IRP “process” also remains largely unchanged from previous IRPs. A seven-step process is used to accomplish the IRP objective, illustrated in Figure 3.

Figure 3: Integrated Resource Planning Seven Step Process



IV. ASSUMPTIONS AND INPUTS

This section describes the major assumptions: (A) OG&E's 2015 load forecast including demand-side resources, (B) Supply-Side resources from existing units and their transition to new resources and environmental control alternatives, (C) SPP transmission additions, (D) Fuel price forecast and CO₂ price forecast used in sensitivity analysis, and (E) SPP Market Price forecast under several scenarios and sensitivities.

A. 2015 Load Forecast and Demand Side Resources

OG&E prepared the July 2015 load forecast that is presented in Appendix A. The load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of electricity prices for price-sensitive customer classes.

Estimates of demand-side resources, incremental to those already reflected in the econometric-based forecast, are developed based on the continued growth in existing OG&E programs and new programs. Growth in Distributed Generation ("DG") is not currently included in the load forecast but is considered in the market price sensitivity section of this report. A more complete discussion of the topic is presented there.

1. Load Forecast – Energy and Peak Demand

Load forecasting includes projections of annual energy sales and peak demand.

a) Energy Sales Forecast Methodology

The retail energy forecast is based on retail sector-level econometric models representing weather, growth and economic conditions in OG&E's Oklahoma and Arkansas service territories. Historical and forecast economic variables (drivers) used in the models are provided by the Center for Applied Economic Research at Oklahoma State University.

b) Peak Demand Forecast Methodology

The load responsibility forecast relies on an hourly econometric model reflecting the:

- Impact of different weekdays on hourly system load;
- Impact of different summer months on hourly system load;
- Influence of heat buildup during heat waves;
- Impact of the combined effects of humidity and warm temperatures; and
- Non-linearity in the load and temperature relationships at very high temperatures;

Historical and forecast weather-adjusted retail energy sales are the main driver for the peak demand forecast projections.

c) Energy Sales and Peak Demand Forecast

The forecast is based on normal weather in both Oklahoma and Arkansas. The energy sales forecast and peak demand forecast are shown in Table 3 and Table 4.

Table 3: OG&E Energy Sales Forecast (GWh)

| GWh | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---------------------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| Retail Energy | 29,628 | 29,950 | 30,218 | 30,477 | 30,756 | 30,993 | 31,203 | 31,434 | 31,676 | 31,936 |
| OG&E DSM | 461 | 563 | 672 | 773 | 869 | 970 | 1,065 | 1,153 | 1,244 | 1,332 |
| Load Responsibility | 29,167 | 29,387 | 29,547 | 29,703 | 29,887 | 30,023 | 30,138 | 30,281 | 30,431 | 30,604 |
| Retail Growth | | 0.76% | 0.54% | 0.53% | 0.62% | 0.46% | 0.38% | 0.48% | 0.50% | 0.57% |

Table 4: OG&E Peak Demand Forecast (MW)

| MW | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---------------------|-------|-------|--------|-------|-------|-------|-------|-------|-------|-------|
| Retail Demand | 6,265 | 6,344 | 6,388 | 6,437 | 6,469 | 6,532 | 6,566 | 6,611 | 6,636 | 6,698 |
| OG&E DSM | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |
| Load Responsibility | 5,898 | 5,916 | 5,900 | 5,924 | 5,931 | 5,968 | 5,978 | 6,000 | 6,001 | 6,041 |
| Retail Growth | | 0.32% | -0.27% | 0.41% | 0.12% | 0.62% | 0.17% | 0.37% | 0.01% | 0.67% |

The Demand Side Management (“DSM”) forecasts reflected in the previous tables represent incremental reductions resulting from increased participation in existing programs and the addition of new programs. The impact of prior program implementation cycles is assumed to be captured in the econometric forecast of retail requirements. These incremental contributions are described in the following paragraphs.

2. Demand Side Management

Demand Side Management (“DSM”) is designed to reduce the load requirements on the system. This appendix shares OG&E’s history with DSM and highlights the current efforts that are included in this load forecast. Most recently, OG&E’s SmartHours program has been described as perhaps the most effective residential demand side management program in the country.

OG&E has successfully managed many energy efficiency (“EE”) and demand response offerings during the past 30 years. As far back as the late 1970’s, OG&E experienced wide spread acceptance of its in-home energy audit program, known as AWARD, that paid customers to make home energy improvements. OG&E had strong participation in its direct load control residential air conditioning program, known as PEAKS, in the 1980’s. OG&E currently offers price response options as well as Day-Ahead Pricing, curtailable and interruptible rate tariffs (which have been in operation since 1997), and several time-of-use tariffs (some of which have been offered since 1985). In addition, OG&E introduced a successful ENERGY STAR® New Home Program in 1996 and continues a new home construction program today. Participation in these programs indicates customers are interested in lowering energy consumption and managing energy use.

OG&E filed a Quick Start Program in Oklahoma Cause No. PUD 200800059 which was in effect until December 31, 2009. The Quick Start Program allowed OG&E to quickly begin offering programs for all classes of customers primarily by providing rebates to help increase customer awareness and to help accelerate market transformation of products such as compact fluorescent lamps. OG&E's first comprehensive portfolio of Demand Programs under Subchapter 41 was approved by the Oklahoma Corporation Commission in Cause No. PUD 200900200 for implementation in years 2010-2012. OG&E's most recent Demand Portfolio was approved by the Commission in Cause No. PUD 201200134 for implementation in years 2013-2015. Since the inception of the QuickStart Program in 2008 through the end of 2014, OG&E has secured a total of 174 MW of demand savings and 374,010 MWh of energy savings. In Arkansas OG&E's Energy Efficiency Cost Recovery (EECR) rider focuses on weatherization, education and commercial customer energy efficiency efforts. Through the end of 2014, OG&E has secured a total of 12 MW of demand savings and 51,942 MWh of energy savings.

a. Home Energy Efficiency Program

This program, available to Oklahoma customers, consists of a home assessment targeted to residential customers who need assistance in identifying areas to improve in both thermal and technology efficiencies. Assistance is offered for air conditioning tune ups, duct repair and inducements offered for additional attic insulation installed. Expansions for the program in 2016 include more options and are expected to increase adoption of energy saving measures for residential customers including hard-to-reach customers, multi-family units and manufactured housing units.

b. Positive Energy-New Home Construction Program

This program encourages builders and homeowners in Oklahoma to utilize energy efficient Positive Energy-New Home Construction practices by installing higher level than required thermal packages in the construction of new homes. Builders will be paid inducements to bring new homes to the higher standards. These homes will be rated and certified by OG&E. This certification allows homebuilders to apply for available tax credits as a result of these upgrades.

c. Weatherization Residential Assistance Program

This program is designed to provide assistance to both lower and fixed income customers by engaging licensed contractors to make improvements to the thermal envelope and to inspect and tune up mechanical equipment in their homes. This work allows customers to better manage energy usage, improve their comfort and makes the living space safer. A similar program is offered in Arkansas.

d. Commercial Energy Efficiency Program

This program is targeted to medium and large commercial customers for the purpose of allowing them to pursue EE projects unique to their business. Inducements will be paid

for kW reduced by these customers. The 2016 program consolidates once stand-alone programs and/or measures (e.g. Commercial Lighting Program, Industrial Energy Efficiency Program) under one umbrella. This offering of multiple energy savings measures and targeted programs will help address the needs of a wider variety of commercial and industrial customers. A similar program is offered in Arkansas.

e. Integrated Volt Var Control (“IVVC”)

The IVVC Program is a system of devices, controls, software and communications products used to manage OG&E’s distribution system reactive power flow and voltage level. This technology is used to reduce energy demand during peak periods and minimize losses, while ensuring acceptable customer voltage levels. During non-peak periods, Volt Var Optimization will normally operate in loss reduction mode. In loss reduction mode, Volt Var Optimization compensates for inefficiencies caused by reactive loads such as electric motors. As a result, energy loss reductions (i.e. energy savings) are expected to be realized during non-peak periods. Volt Var Optimization will be placed in demand reduction or combined loss/demand reduction mode when needed to help reduce system peak energy demand. Demand reduction mode reduces voltage in order to achieve a corresponding reduction in peak energy consumption. Based on study results achieved to date, a peak demand reduction of approximately 2% has been achieved across the circuits on which this technology has been deployed. Over the next 10 years, IVVC is expected to reduce OG&E’s load requirement by 82 MW.

f. Load Reduction Rider (“LRR”)

The Load Reduction program offers financial incentives to commercial and industrial customers that can reduce their electrical load when notified by OG&E. Customers subscribe to an amount of demand reduction (200kW and above) and then receive a discount for that promised reduction. Those who reduce their usage during a called event receive a discount on their next electric bill. OG&E continues to grow this program and plans to achieve over 130 MW reduction by 2025.

g. SmartHours

The SmartHours program integrates technology and pricing to help customers reduce energy usage at peak times. The program utilizes the Advanced Metering Infrastructure to securely send price signals across the network and through the smart meter, directly to the Programmable Communicating Thermostat. Signals are also sent via text message and email. Customers respond to these price signals between the weekday hours of 2:00 p.m. and 7:00 p.m. over the four summer months of June, July, August and September and help reduce the peak demand on the system. In 2015 the Company will achieve the goal of enrolling approximately 20% of residential customers into the SmartHours program. Likewise, commercial and industrial customers will be able to take advantage of more price response programs in the future with an overall combined system coincident peak demand reduction of approximately 150 MW.

Table 5 and Table 6 present the combined Oklahoma and Arkansas demand portfolio estimates of the impact of DSM programs on the load forecast. OG&E will continue promoting and monitoring these programs and will revise future estimates as appropriate.

Table 5: Forecasted Energy Reduction from DSM (GWh)

| GWh | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------------------|------|------|------|------|------|------|-------|-------|-------|-------|
| Current Portfolio | 318 | 318 | 318 | 317 | 316 | 313 | 307 | 300 | 293 | 285 |
| 2016 Portfolio: EE | 94 | 191 | 294 | 294 | 294 | 293 | 292 | 290 | 286 | 281 |
| 2019 Portfolio: EE | - | - | - | 101 | 198 | 301 | 301 | 301 | 300 | 299 |
| 2022 Portfolio: EE | - | - | - | - | - | - | 101 | 198 | 301 | 301 |
| 2025 Portfolio: EE | - | - | - | - | - | - | - | - | - | 101 |
| IVVC | 25 | 29 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| LRR | 3 | 4 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 |
| Smart Hours | 21 | 21 | 22 | 23 | 23 | 24 | 25 | 25 | 25 | 26 |
| Total Net Energy Reduction | 461 | 563 | 672 | 773 | 869 | 970 | 1,065 | 1,153 | 1,244 | 1,332 |

Table 6: Forecasted Peak Demand Reduction from DSM (MW)

| MW | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------------------|------|------|------|------|------|------|------|------|------|------|
| Current Portfolio | 81 | 81 | 81 | 81 | 80 | 79 | 78 | 76 | 74 | 72 |
| 2016 Portfolio: EE | 20 | 42 | 66 | 66 | 66 | 66 | 65 | 65 | 64 | 63 |
| 2019 Portfolio: EE | - | - | - | 22 | 44 | 68 | 68 | 68 | 67 | 67 |
| 2022 Portfolio: EE | - | - | - | - | - | - | 22 | 44 | 68 | 68 |
| 2025 Portfolio: EE | - | - | - | - | - | - | - | - | - | 22 |
| IVVC | 54 | 67 | 82 | 82 | 82 | 82 | 82 | 82 | 82 | 82 |
| LRR | 62 | 88 | 109 | 112 | 116 | 119 | 123 | 126 | 130 | 133 |
| Smart Hours | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| Total Net Demand Reduction | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |

B. Supply-Side Resources

As described in Section II, OG&E remains obligated to maintain capacity sufficient to serve its peak load requirements, either through OG&E-owned generation or contracts for capacity. OG&E's capacity planning reserve margin is 12% and must be satisfied by existing resources (net of any planned retirements) or new capacity resources. OG&E's existing resources and potential new resources (by technology) are presented in this section.

1. Existing Resources

OG&E owns generation and obtains capacity and energy from several purchase power agreements ("PPAs"). OG&E's generation resources include coal-fired units, gas-fired steam units, gas-fired combined cycle ("CC") units, quick start gas-fired combustion turbine ("CT") units, and wind facilities. OG&E owns 51% of the Redbud CC plant and 77% of the McClain CC plant. All other fossil plants are fully owned by OG&E. OG&E is the operator of all of its fossil plants, including McClain and Redbud. OG&E also owns three wind facilities: Centennial, OU Spirit and Crossroads.

OG&E's PPAs include 320 MW from the qualifying facility AES plant at Shady Point that burns coal and 120 MW from the natural gas fired combined cycle Oklahoma Cogeneration plant. OG&E currently has four wind energy PPAs: Sooner Wind at 50 MW, Keenan at 151.8 MW, Taloga at 130 MW and Blackwell at 60 MW. OG&E's fossil fuel PPAs contribute 440 MW of peak capacity while PPAs from wind contribute 20 MW due to their non-dispatchable qualities. OG&E's portfolio of electric generating facilities is presented in Table 7.

Table 7: OG&E Existing Generation Resources – 2016 Peak Planning Capacity*

| Unit Type | Unit Name | First Year In Service | Capacity (MW) |
|--|-----------------------|-----------------------|---------------|
| Coal Fired Steam (2,516 MW) | Muskogee 4 | 1977 | 487 |
| | Muskogee 5 | 1978 | 503 |
| | Muskogee 6 | 1984 | 485 |
| | Sooner 1 | 1979 | 521 |
| | Sooner 2 | 1980 | 520 |
| Gas Fired Steam (2,492 MW) | Horseshoe Lake 6 | 1958 | 166 |
| | Horseshoe Lake 8 | 1969 | 411 |
| | Mustang 1 | 1950 | 0 |
| | Mustang 2 | 1951 | 51 |
| | Mustang 3 | 1955 | 117 |
| | Mustang 4 | 1959 | 257 |
| | Seminole 1 | 1971 | 492 |
| | Seminole 2 | 1973 | 500 |
| Combined Cycle (1,205 MW) | Seminole 3 | 1975 | 498 |
| | Horseshoe Lake 7 | 1963 | 221 |
| | McClain | 2001 | 376** |
| Quick Start Combustion Turbine (157 MW) | Redbud | 2002 | 608** |
| | Horseshoe Lake 9 | 2000 | 45 |
| | Horseshoe Lake 10 | 2000 | 45 |
| | Mustang 5A | 1971 | 34 |
| | Mustang 5B | 1971 | 33 |
| Purchase Power - Thermal (440 MW) | Seminole 1GT | 1971 | 0 |
| | AES Shady Point | 1990 | 320 |
| Purchase Power - Wind (20 MW) | Oklahoma Cogeneration | 1989 | 120 |
| | FPL Wind | 2003 | 4 |
| | Keenan | 2010 | 9 |
| | Taloga | 2011 | 2 |
| Owned Wind (31 MW) | Blackwell | 2012 | 5 |
| | Centennial | 2007 | 16 |
| | OU Spirit | 2009 | 5 |
| Total Net Capability | Crossroads | 2012 | 10 |
| | | | 6,861 |

*See steam gas unit retirement dates in Figure 4. OG&E does not assume retirement dates that are outside the 30-year study period.

** Represents OG&E owned interest.

2. Retirement Assumptions

Historically, OG&E assumed for planning purposes that each generating unit in its fleet would perform for the entire study period. However, the aging of OG&E's fleet necessitated a change in this approach and the 2012 IRP contained end of life dates for the units located at the Mustang, Horseshoe Lake and Seminole plants.

Subsequent to the 2012 submittal, OG&E focused more closely on the Mustang plant. This was in large part because these units are some of the oldest generation units of their type and size operating in the US.³ In addition, OG&E expects the operation of Mustang units in the SPP IM to evolve even further from their original purpose resulting in a seasonal role with increased cycling for short periods. Operating older steam units in a manner not consistent with the purpose for which they were originally designed will, as a practical matter, tend to shorten the estimated useful life for those units.

OG&E's more specific analysis of the Mustang units' age as compared to their peers in the industry and their anticipated future operations caused the company to conclude that the risk of significant failure for these units is substantial and increasing every year. Moreover, if failure occurs in any one of several critical components of a Mustang unit, including but not limited to the turbine, boiler headers, external high energy piping, or a generator step up transformer, the units could be unavailable to meet load requirements for an extended time or even permanently. This is, in part, because replacement parts for units of this age are often no longer supported by manufacturers and, if they can be reproduced at all, must be specially made at a significant expense and lead time. Taking into account the probability and potential impact of equipment failure, as well as the associated safety issues for our members OG&E concluded that, while the Mustang units should remain operational in the near term, retiring all of the Mustang units by the end of 2017 is the prudent course of action. This date represents the earliest generation can be designed, permitted, procured and installed at the Mustang location.

OG&E believes that utilizing the existing Mustang site to replace the 463 MW of reserve planning capacity being retired is prudent for a variety of operational reasons. First, the Mustang plant serves a crucial reliability support function because of its location within the load area. Mustang is located only 9 miles from downtown Oklahoma City, within OG&E's largest load center. Under extreme conditions such as those identified in the Department of Homeland Security report *Terrorism and Electric Power Delivery System*⁴ and recently reported in the *Wall Street Journal*⁵, the Mustang units are available to supply power to a load "island" that could include the critical national security site of Tinker Air Force Base. The Mustang site plays an especially important role in the

³ For example, according to SNL, Mustang unit 4 is the oldest gas steam unit of its size in the United States. Also, there is only one unit in the U.S. older than Mustang Units 1 and 2 of similar size and only six units in the U.S. older than Mustang 3 of similar size. All of the Mustang steam units are already well beyond the average life for this type of unit (52 years).

⁴ National Research Council. *Terrorism and the Electric Power Delivery System*. Washington, DC: The National Academies Press, 2012.

⁵ Smith, R. (2014, March 12). *U.S. Risks National Blackout From Small-Scale Attack*. *Wall Street Journal*

service restoration process. The Company's service restoration plan designates Mustang as a key contributor in re-energizing the system in black start situations and helping get our other units back on-line in those events. Locating quick-starting combustion turbines at Mustang would speed up the system restoration process and allow OG&E to restore the system faster in the event of a black start situation. Having generation close to OG&E's largest load center also mitigates OG&E's exposure to prolonged storm-related outages on the transmission system.

Mustang also provides valuable voltage control on the transmission system. Given the close proximity of the Mustang plant to Oklahoma City, and since the Mustang plant is configured to flow power into both the 69 kV and 138 kV transmission systems, it serves a critical role as a dynamic resource to stabilize voltage on the part of our transmission system that directly serves the majority of our customers. The Mustang location allows the transmission system operators the ability to operate within North American Electric Reliability Corporation ("NERC") and regionally-mandated criteria, and mitigates the prospect for sudden, substantial voltage collapses on the system.

In addition, Mustang has an existing infrastructure in place to support operation and maintenance of the plant including: secure property, electric transmission and interconnection facilities, a gas pipeline connection, available water supply with water rights, roads and buildings.

Mustang's existing environmental air permits provide the opportunity to use the permitting process for gas-fired generation on OG&E's system. This opportunity is based on a "netting analysis" whereby the emissions from replacement generation are "netted" against the historical emissions from the existing units. Since operation of the existing Mustang units is expected to decline in the IM market, permitting the new units in the near term will maximize the amount of replacement generation capacity that can be installed at the Mustang site.

The company concluded that CTs, with their ability to start quickly and react faster to SPP market signals, will be dispatched more frequently in the SPP market. Similarly, with the growing amount of intermittent wind generation within the SPP footprint, these new CT units will be able to react quicker to changes in wind patterns and will complement the growing wind generation in the state and region. As the amount of wind generation and solar energy in the SPP market grows, this type of agile gas generation is expected to be even in more demand. The need for additional quick start CT capacity has been identified in several of SPP's Integrated Transmission Plans including the latest plan. OG&E also determined that no CT's are available for acquisition in the region.

For all of these reasons, OG&E believes that retirement of the Mustang steam units at the end of 2017 and the replacement of those units with CT's at the existing site is the best course of action. These assumptions are used in the IRP analysis. In addition, OG&E has performed an analysis comparing this approach to other options for retiring the four Mustang units and replacing the capacity. The results of that analysis are

discussed in Section V. The assumed retirement dates for the remaining gas-fired steam units are reflected in Figure 4.

Figure 4: Assumed Gas-Fired Steam Unit Retirements

| Horseshoe Lake Plant | Seminole Plant |
|------------------------|------------------------|
| Unit 6 (169 MW) – 2024 | Unit 1 (486 MW) – 2037 |
| Unit 7 (209 MW) – 2029 | Unit 2 (482 MW) – 2039 |
| Unit 8 (394 MW) – 2035 | Unit 3 (489 MW) – 2041 |

As with the Mustang Units, these dates are assumptions that may be adjusted over time to reflect contemporary conditions.

3. Emission Control Technologies

Several existing generation units will require emission control equipment to comply with federal and state emissions regulations. Compliance with Regional Haze requirements under the EPA's FIP will require either the installation at Sooner 1 and 2 and Muskogee Units 4 and 5 of Dry Scrubber technology or conversion to natural gas. Several coal and gas-fired units will require installation of Low NO_x Burners to comply with Regional Haze and potentially for CSAPR rules that are soon to be finalized. Activated Carbon Injection will be utilized to address MATS. Estimates for natural gas transportation fees to support the potential conversion from coal to natural gas at both Muskogee and Sooner plants have also been developed to capture the complete cost associated with this environmental compliance alternative. OG&E anticipates that a competitive bidding process will be necessary to construct new pipeline capacity to serve Muskogee to support the conversion. Cost estimates for emission control technologies considered in this IRP are based on information provided by Sargent & Lundy, shown in Table 8.

Table 8: Emission Control Technologies (2015 Dollars)

| Control | Units | Overnight Capital Cost (\$Millions) | Fixed O&M Cost (\$Millions) | Variable O&M Cost (\$/MWh) |
|-----------------------------|-------------------|-------------------------------------|-----------------------------|----------------------------|
| Dry Scrubber | All Coal per unit | \$245.0 | \$7.94 | \$2.75 |
| Low NO _x Burners | Muskogee 4 | \$9.3 | \$0.24 | - |
| Low NO _x Burners | Sooner 1 | \$11.9 | \$0.24 | - |
| Low NO _x Burners | Seminole 1&2 | \$43.1 | \$1.31 | - |
| Low NO _x Burners | Seminole 3 | \$19.6 | \$0.65 | - |
| Activated Carbon Injection | All Coal | \$22.7 | \$0.81 | \$2.52 |
| Conversion to Gas | Muskogee per unit | \$38.0 | (\$5.62) | (\$0.12) |
| Conversion to Gas | Sooner per unit | \$38.0 | (\$5.80) | \$0.39 |

**Represents the incremental cost decrease due to conversion from coal to gas*

4. New Build Supply-Side Resources

OG&E utilized the 2015 Energy Information Administration (“EIA”) Annual Energy Outlook to identify proxy supply side resources. The proxy units are meant to represent a generic type of unit and not the specific manufacturer or technology to be placed into service. The EIA data was used only to screen viable generation technologies to consider. Two requirements were established for selecting new resources to analyze: (1) whether the technology was proven, and (2) whether the cost was economically viable. Resources had to satisfy both requirements in order to be subject to further analysis. The supply-side resource options and screening requirements are presented below in Table 9.

Table 9: New Resource Screening Requirements (2015 Dollars)

| Type | Technology | Capacity (MW) | Overnight Capital Cost (\$/kW) | Proven Technology | Cost |
|--------------------|--------------------------------|---------------|--------------------------------|-------------------|------|
| Coal | Single Unit Advanced PC | 650 | 3,374 | Yes | |
| | Dual Unit Advanced PC | 1,300 | 3,050 | Yes | |
| | Single Unit Advanced PC w/ CCS | 650 | 5,433 | | |
| | Dual Unit Advanced PC w/ CCS | 1,300 | 4,910 | | |
| | Single Unit IGCC | 600 | 4,573 | | |
| | Dual Unit IGCC | 1,200 | 3,933 | | |
| | Single Unit IGCC with CCS | 520 | 6,859 | | |
| Natural Gas | Conventional NGCC | 620 | 953 | Yes | Yes |
| | Advanced NGCC | 400 | 1,063 | | Yes |
| | Advanced NGCC with CCS | 340 | 2,178 | | Yes |
| | Conventional CT | 85 | 1,011 | Yes | Yes |
| | Advanced CT | 210 | 703 | Yes | Yes |
| | Fuel Cells | 10 | 7,388 | | |
| Uranium | Dual Unit Nuclear | 2,234 | 5,748 | Yes | |
| Biomass | Biomass CC | 20 | 8,502 | Yes | |
| | Biomass BFB | 50 | 4,276 | Yes | |
| Wind | Onshore Wind | 100 | 2,300 | Yes | Yes |
| | Offshore Wind | 400 | 6,475 | Yes | |
| Solar | Solar Thermal | 100 | 5,267 | Yes | |
| | Small Photovoltaic | 20 | 4,348 | Yes | * |
| | Large Photovoltaic | 150 | 4,026 | Yes | |
| Geo-thermal | Geothermal - Dual Flash | 50 | 6,489 | Yes | |
| | Geothermal - Binary | 50 | 4,534 | Yes | |
| MSW | Municipal Solid Waste | 50 | 8,639 | Yes | |
| Hydro | Hydro-electric | 500 | 3,052 | Yes | |
| | Pumped Storage | 250 | 5,496 | Yes | |

*Updated Overnight Capital Cost is approximately \$2,500/kW as shown in Table 10

a) Proven Technology

In addition to providing construction and operating costs associated with the new resources, the Annual Energy Outlook also discusses how some technologies are more developed than others. For example, while carbon capture and sequestration is discussed as a solution to reduce CO₂ emissions, repeated utility scale facilities have not been developed and operated. Therefore this technology is not considered proven and is not included in a resource portfolio. The advanced units in the Annual Energy Outlook are typically not technologies proven on a commercial scale.

b) Cost

The second requirement considers the cost of the new resource option. For example, the Biomass CC unit has a cost of \$8,502/kW. This is significantly more expensive than other renewable or base load resource options; therefore it would not be a reasonable addition to a portfolio. For purposes of the cost/scale criterion, technologies that have overnight capital costs of less than \$2,500/kW are assumed to pass the test.

As described in the following paragraphs, OG&E supplemented the EIA data for both wind and central solar facilities through a Request for Information (“RFI”) in the case of wind energy and further research with respect to central solar facilities. In both cases, the costs are lower than suggested by the EIA analysis.

c) 2015 OG&E RFIs

On May 18, 2015, OG&E issued a wind RFI to gain market intelligence of wind energy pricing and availability. Respondents were required to provide pricing and terms demonstrating the respondent’s willingness to accept operational and transmission congestion risk. By June 21, 2015, responses were received from fourteen (14) companies that offered twenty one (21) locations throughout Oklahoma, Texas and Kansas.

OG&E also issued a solar RFI on May 18, 2015 to gain market intelligence of solar energy pricing and availability. By June 21, 2015, responses were received from fourteen (14) companies that offered twenty five (25) locations throughout Oklahoma, Texas and New Mexico.

OG&E continues to analyze the wind and solar responses including conducting congestion and market revenue studies.

On June 8, 2015, OG&E issued a Request for Information (“RFI”) for up to 200 MW of fossil fuel purchase power capacity to be delivered between May 1, 2020 and August 31, 2022. OG&E received four (4) responses with only two (2) of the responses offering purchase power agreements as requested in the RFI. OG&E is in the process of evaluating such options and whether entering into a short term PPA will allow OG&E to delay the addition of new generation capacity until 2023.

d) Solar Photovoltaic

To gain installation and operational experience, OG&E has installed solar photovoltaic generation at three locations. The first two installed in 2014 are on the rooftops of Company service center buildings in geographically diverse locations. The third is 2.5 MW of central solar generation installed at the Mustang Power Plant and became operational in July of 2015.

Central Solar Photovoltaic (“PV”) requires 10-15 acres per MW. Two types of Solar PV systems were evaluated⁶ to estimate potential revenues and costs. The first type of system is a fixed tilt system that has an estimated cost of about \$2.25 per watt and 18.5% capacity factor. This unit also has less coincidence with peak so the capacity value is estimated at 50%. The second unit evaluated, a single axis tracking system, is more expensive at nearly \$2.50 per watt but appears to be more beneficial to customers since it operates with an estimated capacity factor of 24% and has a higher coincident capacity value of 70%. The estimated maintenance cost is \$25 - \$40 per kW-year and includes an inverter replacement once every 10 years. The assumptions are summarized in Table 10.

Table 10: Central Solar Photovoltaic (2015 Dollars)

| | Cost (\$/kW) | Size (MW) | Capacity Factor | Energy (MWh) | Fixed O&M (\$/kW-yr.) |
|--------------------|-----------------|--------------|--------------------|-----------------|--------------------------|
| Single Axis | \$2,518 | 10 | 23.9% | 20,971 | \$40 |
| Fixed Tilt | \$2,247 | 10 | 18.5% | 16,246 | \$25 |

e) Sargent & Lundy estimates

A select group of practicable technologies was selected for more in depth study. The new supply side resources utilized for detailed analysis were provided in the IRP Technology Assessment: New Gas Generating Options by Sargent & Lundy. A summary is shown in Table 11.

Table 11: New Supply Side Resources (2015 Dollars)

| Type | Technology | Net Capacity (MW) | Heat Rate (Btu/kWh) | Overnight Capital Cost (\$/kW) | Fixed O&M Cost (\$/kW) | Variable O&M Cost (\$/MWh) |
|------------------------|--------------------|-------------------------|------------------------|--------------------------------------|------------------------------|----------------------------------|
| Natural Gas | Combined Cycle | 281 | 6,120 | \$1,499 | \$22.87 | \$2.60 |
| | Combined Cycle | 562 | 6,120 | \$1,247 | \$16.63 | \$2.60 |
| | Combustion Turbine | 39 | 8,904 | \$1,019 | \$27.02 | \$1.84 |
| | Combustion Turbine | 75 | 10,733 | \$1,102 | \$22.87 | \$18.71 |
| | Combustion Turbine | 86 | 8,309 | \$1,684 | \$16.63 | \$4.57 |
| | Combustion Turbine | 237 | 9,040 | \$1,001 | \$8.32 | \$16.63 |

⁶ The overall cost per watt taken from the publically available documentation provided by Arizona Public Service Company. The capacity factors were derived using load data provided from a solar vendor’s engineering model using Oklahoma City location characteristics.

5. Transmission to Connect New Supply-Side Resources

Supply side resource options often require transmission investments depending on location and the configuration of existing transmission facilities. In an effort to develop a more comprehensive estimate of the costs of new generation, OG&E has identified proxy sites and estimated the transmission expansion costs that would be associated with these sites. These sites were chosen for analysis purposes only and no determination has been made on future specific locations.

a) Thermal Generation

A Transmission Service study was performed by OG&E for the purpose of analyzing the transmission constraints associated with the addition of one 562 MW generating unit to the McClain generation plant. The McClain plant is located in McClain County near Newcastle, Oklahoma. The addition of the unit will require expansion of the McClain substation to include a 345kv Bus. The estimated expansion cost is \$20 million as detailed in Table 12.

Table 12: Estimated Expansion Cost at McClain Substation

| Description | Estimated Cost |
|--|---------------------|
| 345kV Substation w/ Cimarron & Draper lines looped | \$12,000,000 |
| 345/138kV Bus tie transformer & low side w/2 line terminals | \$3,000,000 |
| Rebuild McClain 138kV for Breaker & 1/2 to accommodate 2 new lines from new McClain Extra High Voltage sub | \$4,000,000 |
| Lines between McClain 138kV & McClain Extra High Voltage Sub | \$1,000,000 |
| Total 345 kV Expansion Cost | \$20,000,000 |

Contingency Analysis was performed to determine if any overloads were present due to new generation. One overload was detected in the Western Farmers Electric Cooperative area and transmission network upgrades will be required to correct the overload. There may be additional cost that will be determined in the SPP study process.

OG&E also examined the potential of adding CTs at the Mustang site and determined that this would not require any additional transmission capacity beyond what is already located at Mustang to allow for transmission service.

C. New Transmission Facilities

OG&E's transmission system is directly interconnected to seven other utilities' transmission systems at over 50 interconnection points. Indirectly, OG&E is connected to the entire Eastern interconnection through the SPP regional transmission organization. The SPP footprint covers 370,000 square miles and serves over 6 million customers and has members in 14 states across all of Kansas and Oklahoma and parts of Arkansas, Iowa, Louisiana, Minnesota, Missouri, Nebraska, New Mexico, North Dakota, South Dakota, Texas and Wyoming. In compliance with FERC Order 890 for

transmission planning, SPP performs annual expansion planning for the entire SPP footprint. OG&E provides input to the SPP planning process, and SPP is ultimately responsible for the planning of the OG&E system.

The 2015 SPP Transmission Expansion Plan⁷ (“STEP”) summarizes Integrated Transmission Planning (“ITP”) efforts including regional reliability, local reliability, generation interconnection, and long-term tariff studies due to transmission service requests. The purpose of the ITP process is to maintain reliability, provide economic benefits and meet public policy needs in both the near and long-term to create a cost-effective, flexible and robust transmission grid with improved access to the SPP region’s diverse resources. The ITP is a three-phase iterative three-year process that includes a long-term 20-year assessment, a 10-year assessment and a near-term assessment.

The first phase, the ITP 20 Year Assessment (“ITP20”) is used as a roadmap for the development of a long-term transmission plan over a 20-year horizon. The ITP20 focuses on the continued development of the SPP region’s extra high voltage (“EHV”) transmission system to reduce congestion and enable low cost generation access to SPP’s members. SPP will not issue any Notifications to Construct as a result of the ITP20. The ITP20 plan process is repeated every three years.

The second phase of the ITP process is the ITP 10-Year Assessment (“ITP10”), which analyzes the transmission grid over a 10-year time frame. The ITP10 utilizes economic and reliability analysis to find solutions for local reliability upgrades, mitigate congestion, improve access to markets and eliminate potential criteria violations.

The third phase of the ITP process is the annual ITP Near-Term Assessment (“ITPNT”). The goals of the ITPNT are to preserve SPP transmission grid reliability and to create an effective near-term plan for the SPP footprint. ITPNT will identify potential problems under normal and first contingency scenarios in compliance with NERC Reliability Standards, SPP Criteria, and local planning criteria. Mitigation plans to meet regional reliability needs will be developed and necessary reliability upgrades will be identified for approval and construction.

The benefits provided by the improvements identified in the 2015 STEP include reliability and the capacity for expansion of Oklahoma’s wind energy. Transmission system expansion provides benefits to members throughout SPP; therefore, the costs of all projects constructed in SPP are shared through various cost allocation methods, depending on the type of project.

SPP’s High Priority Incremental Load Study (“HPILS”) evaluated transmission needs resulting from significant incremental load growth expectations in certain parts of SPP. The SPP Board of Directors approved the HPILS report⁸ and the projects recommended for construction on April 29th, 2014. These projects are indicated by High Priority in

⁷ 2015 STEP http://www.spp.org/publications/2015_STEP_Report.pdf

⁸ http://www.spp.org/publications/FINAL_HPILS_Report.zip

Table 13. The 2015 STEP included the following major 345 kV transmission projects in the OG&E area. A more descriptive list of those projects can be found in Schedule J. The Projects with the Facility Owner designated as To Be Determined (“TBD”) in Table 13 will be included in the SPP Transmission Owner Selection Process (“TOSP”) which will competitively solicit proposals for projects that no longer have Right of First Refusal (“ROFR”).

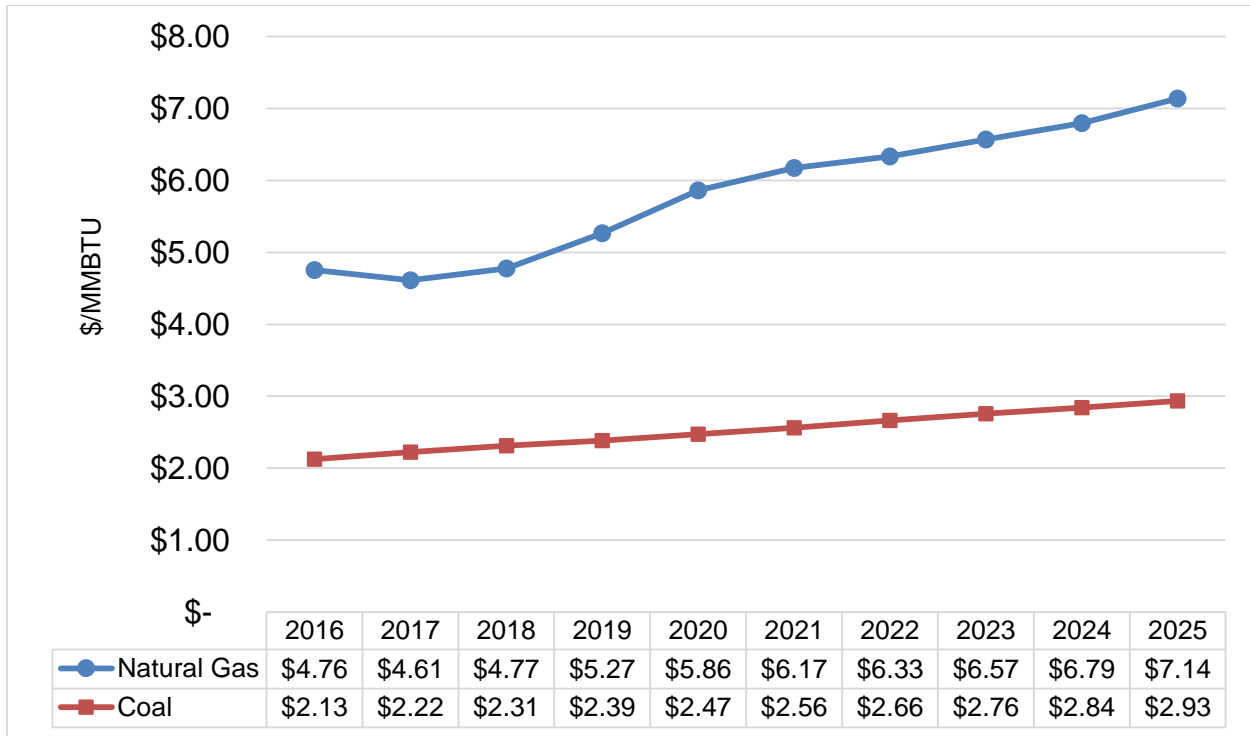
Table 13: Major 345 kV Transmission Projects

| Project Type | Description | Year | Facility Owner |
|-----------------------------------|---|------|----------------|
| Generation Interconnection | New Substation for GEN-2012-040 | 2015 | TBD |
| Generation Interconnection | Woodward EHV 345 KV for GEN-2007-062 - Line terminal including two 345 KV circuit breakers, line relaying, disconnect switches and associated equipment | 2015 | OGE |
| Generation Interconnection | New Windfarm at Matthewson - 345 KV line terminal including one 345 KV circuit breaker, line relaying, disconnect switches and associated equipment | 2015 | OGE |
| Generation Interconnection | New Windfarm at Beaver County - 345 KV line terminal including one 345 KV circuit breaker, line relaying, disconnect switches and associated equipment | 2015 | OGE |
| Transmission Service | Convert Ft. Smith 161 KV to 1 - 1/2 breaker design and install 3rd 500 to 161 KV transformer | 2017 | OGE |
| ITP | 30 miles of a 100 mile new 345 KV line from Gracemont towards Chisholm Substation (AEP) | 2018 | OGE |
| Transmission Service | 5 miles of 345 KV line from Arcadia to Redbud (3rd line) in central Oklahoma | 2019 | OGE |
| ITP | Upgrade CT and wavetrap at both Cimarron and Draper 345 KV substations | 2019 | OGE |
| ITP | 49 miles of a new second circuit 345 KV line from Woodward District EHV to Tatonga | 2021 | OGE |
| ITP | 61 miles of a new second circuit 345 KV line from Tatonga to Matthewson | 2021 | OGE |
| ITP | 16 miles of new second circuit 345 KV line from Matthewson to Cimarron | 2021 | OGE |
| ITP | Build new Matthewson 345 KV Substation at the intersection of the Woodring - Cimarron and Northwest - Tatonga 345 KV lines | 2021 | OGE |
| High Priority | Cut in to 345 KV line from Border to Woodward District EHV and construct new 0.5 mile line to terminating at Chisholm 345 KV creating a Border - Chisholm EHV 345 KV line. | 2021 | TBD |
| High Priority | Cut in to 345 KV line from Border to Woodward District EHV and construct new 0.5 mile line to terminating at Chisholm 345 KV sub creating a Chisholm - Woodward District EHV 345 KV line. | 2021 | TBD |

D. Fuel and CO₂ Assumptions

The Fuel Price forecast for this IRP is from the Energy Information Agency’s (EIA) 2015 Annual Energy Outlook. Both the coal and natural gas prices are shown in Figure 5.

Figure 5: EIA Fuel Forecast (Annual Average)



The 2015 Annual Energy Outlook assumes that there are no explicit federal regulations to limit greenhouse gas emissions, therefore a CO₂ emission price was only included in the analysis as a sensitivity and is shown in Table 14.

Table 14: CO₂ Price Forecast (\$/ton)

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|--------|------|------|------|------|------|------|------|------|------|------|
| \$/ton | \$0 | \$0 | \$0 | \$0 | \$15 | \$16 | \$16 | \$16 | \$18 | \$20 |

E. Integrated Marketplace Prices

OG&E and the other members of SPP are now participating in the SPP IM which has implications for the way OG&E plans for generation resources. Since OG&E sells its generation into the market and buys all of its load requirements from the market, it is necessary to calculate future market prices to reflect in the modeling process. OG&E utilizes Ventyx PROMOD IV®, an Electric Market Simulation tool which incorporates generating unit operating characteristics, transmission grid topology and constraints, to determine future energy prices in the SPP IM.

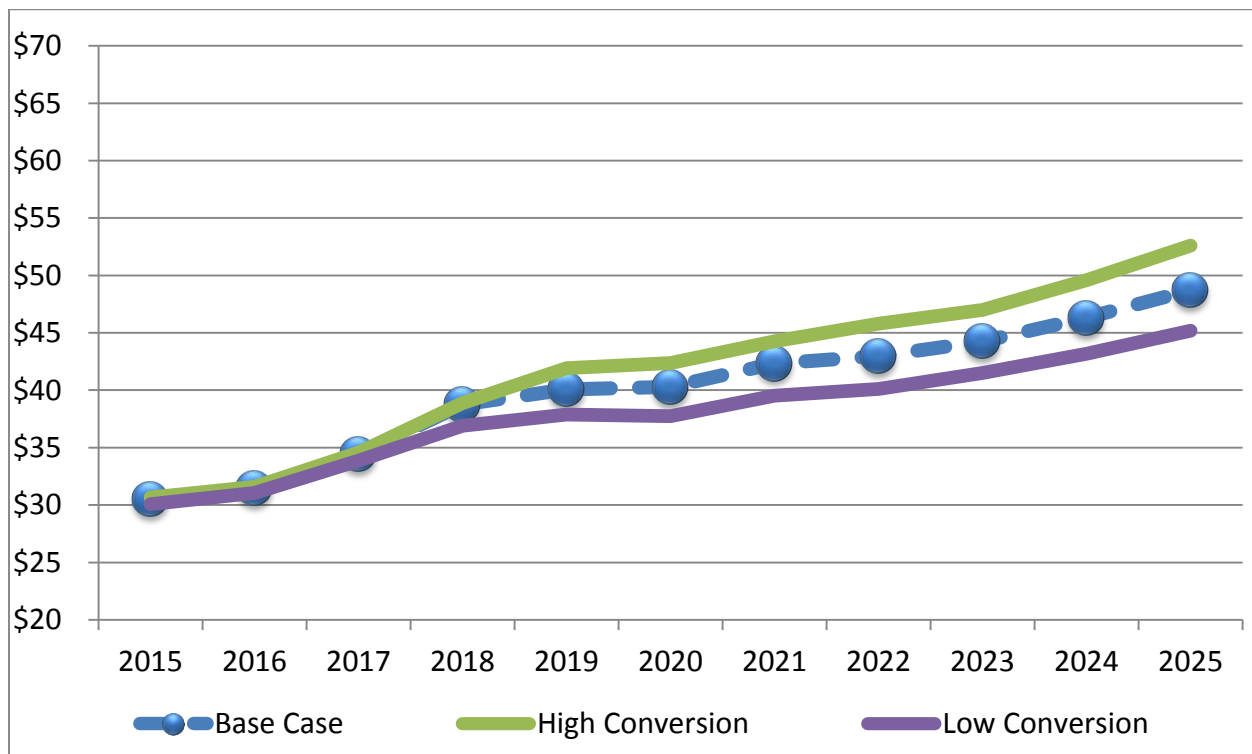
1. Market Price Scenarios

Market conditions such as availability of diverse generation resources, fuel pricing and emission costs will impact market pricing. To capture the uncertainties associated with these market drivers, OG&E has developed three market scenarios that it believes are plausible outcomes. The likelihood that SPP members will be required to control emissions on their coal plants was used to define the three scenarios:

- **Base Case** – All announced plans to control emissions on SPP coal units are included in the models. Also, it is assumed all coal units in SPP smaller than 200 MW and all units older than 1977 that do not have emission controls will be converted to natural gas. All other coal units with and without emission control are assumed to be available in the IM.
- **High Conversion** – Starting with the Base Case scenario, all coal units in SPP that have not announced plans to control emission are assumed to be converted to natural gas.
- **Low Conversion** – All announced plans to control emission on SPP units are included in the models. All other coal units with and without emission control are assumed to be available in the IM.

The resulting average annual Locational Marginal Prices (“LMPs”) for the three scenarios are shown in Figure 6

Figure 6: SPP Market Scenarios (Annual Average \$/MWh)



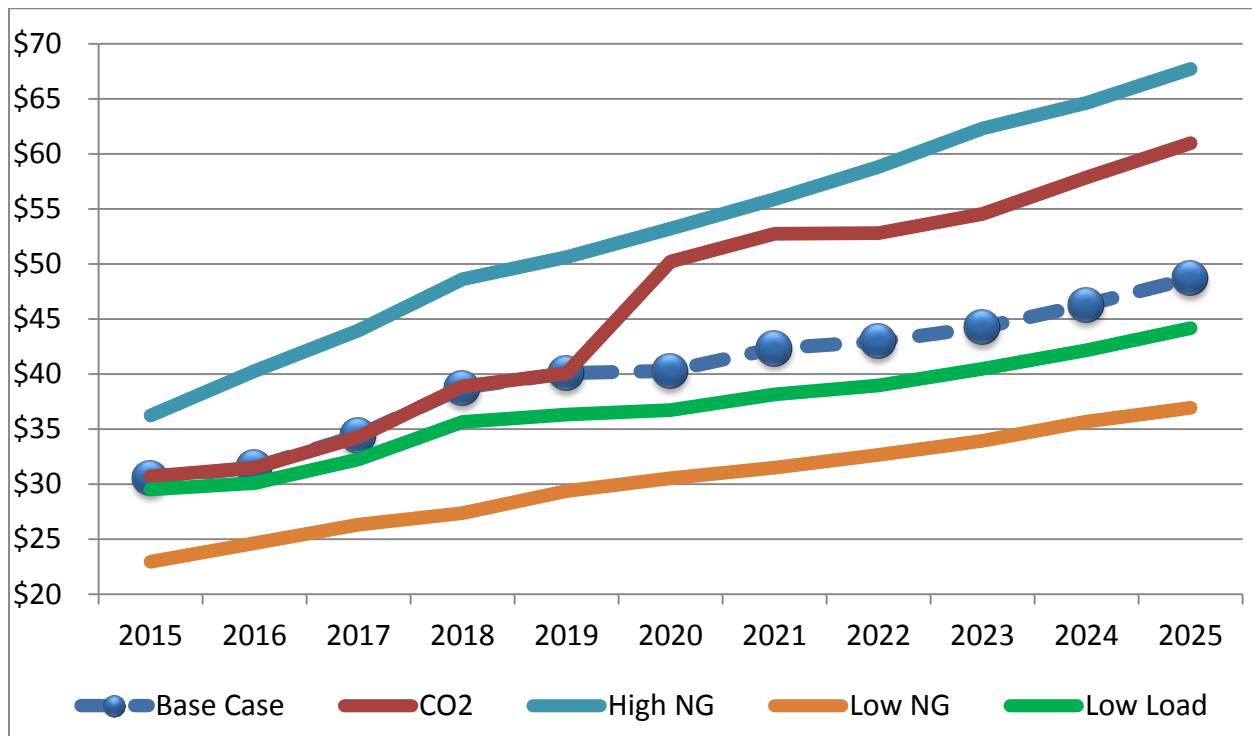
2. Market Price Sensitivities

Potential market prices due to the uncertainty of natural gas prices, the potential for a CO₂ tax and load requirements were considered through the development of sensitivities. These sensitivities were developed by changing each assumption associated with the uncertainties listed below one at a time in the model. The result was four sets of market prices that reflect these uncertainties.

- High Natural Gas - Natural gas prices 1.5 times as much as the Base Case gas price
- Low Natural Gas - Natural gas prices 0.75 times as much as the Base Case gas price
- CO₂ – CO₂ tax is included in 2020
- Low Load - Load across the SPP footprint declines by 10% over the next 10 years because of the increased prevalence of distributed generation

The prices define a range of possible prices in the IM. The resulting average annual LMPs of the Base Case scenario versus the four sensitivities are shown in Figure 7.

Figure 7: Market Prices for Sensitivity Analysis (Annual Average \$/MWh)



a) Discussion of Distributed Generation

DG is defined as electricity production that is on premise or close to the customer load and is interconnected to the utility distribution system. The most common DG technologies currently being adopted include solar photovoltaic, fuel cells and micro-

turbines. In most applications, DG can be a substitute product for grid-supplied electricity.

DG growth is increasing in certain states due to policies favorable to DG, tax incentives, state-level equipment rebates and relatively high electricity prices. Since these conditions are not prevalent throughout the SPP footprint, the near term impacts of DG on SPP load and energy prices are not estimated to be material.

However, suppliers of DG systems are structuring their product financing to be more affordable. Additionally, technological advancements and market dynamics are expected to reduce the overall costs of DG systems over the next decade. As a result DG systems will likely become more attractive to customers within OG&E's service territory and SPP. Given these factors, there is potential for the adoption of DG systems to grow more rapidly in five to ten years.

In modeling the market price sensitivity, OG&E considered the impact to SPP market prices if energy from DG systems reduced total SPP load by an incremental 1% per year over the next ten years for a total of 10% reduction by 2025.

V. RESOURCE PLANNING MODELING AND ANALYSIS

This section describes the resource planning analysis that OG&E has performed by applying the process described in Section III. All analyses begin with the assumption that OG&E is obligated to acquire capacity to meet its SPP capacity planning margin requirement of 12% as described in Section II.

OG&E relies on the Ventyx PROMOD IV® software to model the SPP IM. OG&E performed base case, sensitivity and scenario analyses based on the assumptions that are described in Section IV. These model runs produce an estimate of the 30-year NPVCC which represents one of the most important IRP objectives – producing the lowest reasonable cost for OG&E’s customers. The sensitivity and scenario analysis results contribute to the assessment of the portfolio’s ability to satisfy other IRP objectives, including the value of fuel diversity. Overall, the model results inform OG&E’s judgment as to the lowest reasonable cost resource portfolio.

A. OG&E’s Capacity Planning Obligation

As described in section II, the SPP capacity planning margin is 12% and considers all resources currently owned or under contract. If expected resources do not reach the level of customer demand plus the minimum 12% margin, additional resources or a reduction in load responsibility is required. The results are presented in Table 15.

Table 15: Planning Capacity Margin (MW unless noted)

| | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------|---------------------------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| Resources | Total Owned Capacity | 6,401 | 6,401 | 5,977 | 5,977 | 5,977 | 5,977 | 5,977 | 5,977 | 5,811 | 5,811 |
| | Purchase Contracts | 460 | 460 | 460 | 456 | 336 | 336 | 336 | 16 | 16 | 16 |
| | Total Net Dependable Capability | 6,861 | 6,861 | 6,437 | 6,433 | 6,313 | 6,313 | 6,313 | 5,993 | 5,827 | 5,827 |
| Demand | Demand Forecast | 6,265 | 6,344 | 6,388 | 6,437 | 6,469 | 6,532 | 6,566 | 6,611 | 6,636 | 6,698 |
| | OG&E DSM | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |
| | Net Demand | 5,898 | 5,916 | 5,900 | 5,924 | 5,931 | 5,968 | 5,978 | 6,000 | 6,001 | 6,041 |
| Capacity Needs | Capacity Margin | 963 | 945 | 536 | 508 | 381 | 345 | 334 | (8) | (174) | (215) |
| | Percent Capacity Margin (%) | 14.0 | 13.8 | 8.3 | 7.9 | 6.0 | 5.5 | 5.3 | (0.1) | (3.0) | (3.7) |
| | Needed Capacity | - | - | 269 | 300 | 428 | 470 | 481 | 826 | 993 | 1,039 |

As shown in Table 15, OG&E’s initial year of need is 2018 due to the prior retirement of Muskogee 3, Enid and Woodward plants and the planned retirement of the thermal units at the Mustang plant.

B. Environmental Compliance Analysis

This section presents the multi-step process used to analyze various environmental compliance alternatives. These steps include the identification of potential portfolios to meet both environmental compliance and longer-term capacity needs followed by detailed modeling analyses including scenario and sensitivity analyses. The final step is the application of IRP objectives and judgment to the set of model analyses to identify the lowest reasonable cost plan.

1. Development of Portfolios

Although the EPA has specified in the FIP that OG&E should limit emissions to comply with Regional Haze, there are several alternatives that should be considered before deciding on the lowest reasonable cost plan. Since the compliance plans do not result in an increase in capacity, it is necessary to combine each plan with a capacity expansion plan before determining which combined compliance/expansion plan will be the best plan for OG&E and its customers. As described below, OG&E has identified five potential Regional Haze compliance alternatives and three potential expansion plans for a total of 15 portfolios to subject to the Ventyx modeling analysis.

a) Regional Haze Compliance Alternatives

OG&E identified five alternatives for controlling SO₂ emissions and complying with the Regional Haze rule as established in the FIP by the 2019 compliance year. Each alternative uses different technologies to achieve required levels of emission reductions, as outlined in Figure 8 that represent variations of three fundamental alternatives: installation of dry scrubbers, conversion of the coal units to natural gas, and replacement of the coal units with new combined cycle plants.

Figure 8: Regional Haze Compliance Alternatives

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

Each of these compliance plan alternatives assume that Low NO_x Burners are installed on the seven Regional Haze impacted units (the four coal units and the three gas steam

Seminole units) by 2017 and that ACI is installed on the coal units by the April 2016 MATS deadline to achieve compliance with respect to mercury standards.⁹

b) Expansion Plan Options

Three expansion plans were developed by considering the SPP 12% planning capacity criteria. As explained in the Retirement Assumptions section, the Mustang units will be retired and options for replacement are analyzed as part of the overall future expansion plan. All expansion plans examined are consistent with OG&E’s “2020 Goal” with no incremental fossil fuel generation added to the resource portfolio until 2020.

OG&E utilizes a screening process as described in Section IV to narrow the options to those that are feasible to OG&E. In this screening process, Combined Cycle units and Combustion Turbine units met all the screening criteria for consideration. OG&E obtained more specific unit data from Sargent and Lundy in order to model the expansion units in the SPP IM. The CCs and CTs were then distributed across the 30-year forecast period with in-service dates as necessary to meet OG&E’s projected capacity needs. Each of the three primary options adds capacity beginning in 2018 to meet the capacity need that will result from the retirement of the Mustang units. They represent an all CC-option (“CC”), a CT followed by CCs (“CT”), and an option that reflects the flexibility offered by smaller sized CT’s by spreading them out over 2 years along with a mix of CTs and CCs (“Spread CT”). These options are presented in Table 16.

Table 16: Expansion Plans

| | 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 | |

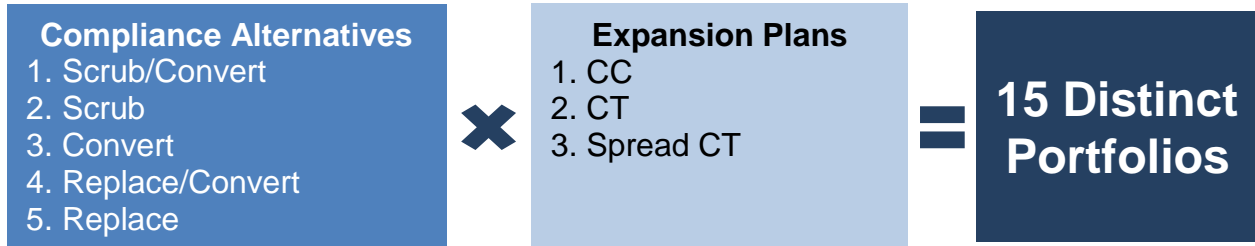
c) Portfolio Identification

The five Regional Haze compliance alternatives were combined with the three expansion plan options to form 15 distinct portfolios. This collection of portfolios allows OG&E to compare the compliance alternatives while also offering insights on the

⁹ Specific installation dates for emission controls must be assumed for modeling purposes and are based on current OG&E plans although the actual installation dates may change somewhat as the development plans are finalized.

benefits of each expansion option. This also allowed OG&E to determine if or how expansion plan options impact the Regional Haze compliance alternatives. These 15 portfolios are shown in Figure 9.

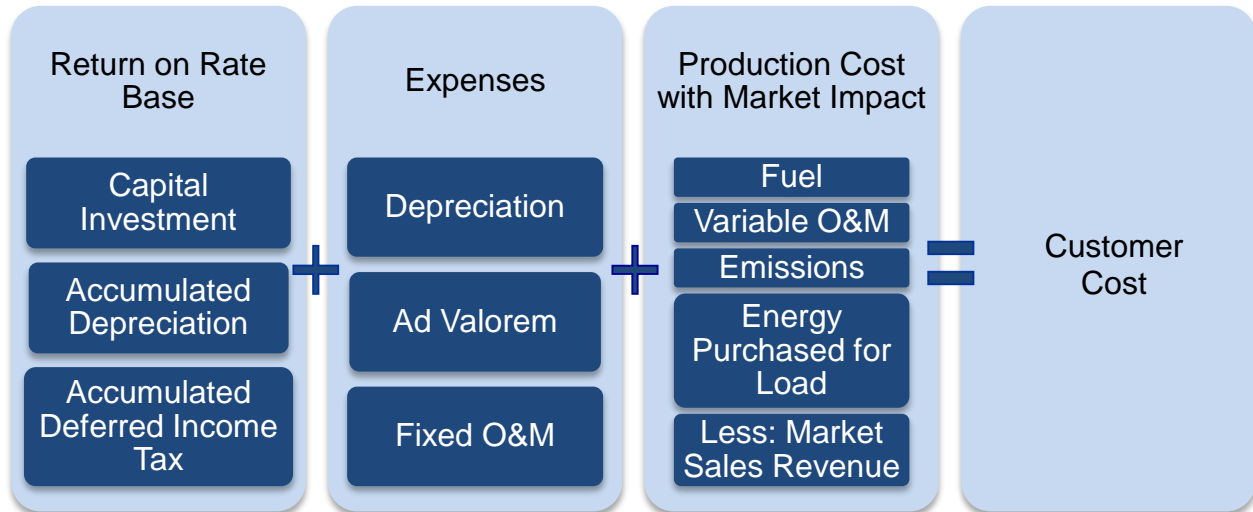
Figure 9: Portfolio Development



2. Portfolio Modeling Analysis

The modeling analysis determines customer costs as measured over the 30-year forecast period. The portfolios are first analyzed using the “Base Case” set of forecast assumptions, before testing the impacts of alternative sets of assumptions by performing scenario and sensitivity analyses. The production cost with market impact of each portfolio is determined utilizing PCI GenTrader® software with a model set-up that represents OG&E’s generating unit characteristics and operating constraints. The OG&E generators are dispatched against the IM price forecast to simulate operations in the SPP IM. The return on rate base and non-production expenses associated with each portfolio is then added to production costs with market impacts to determine the customer costs as shown in Figure 10.

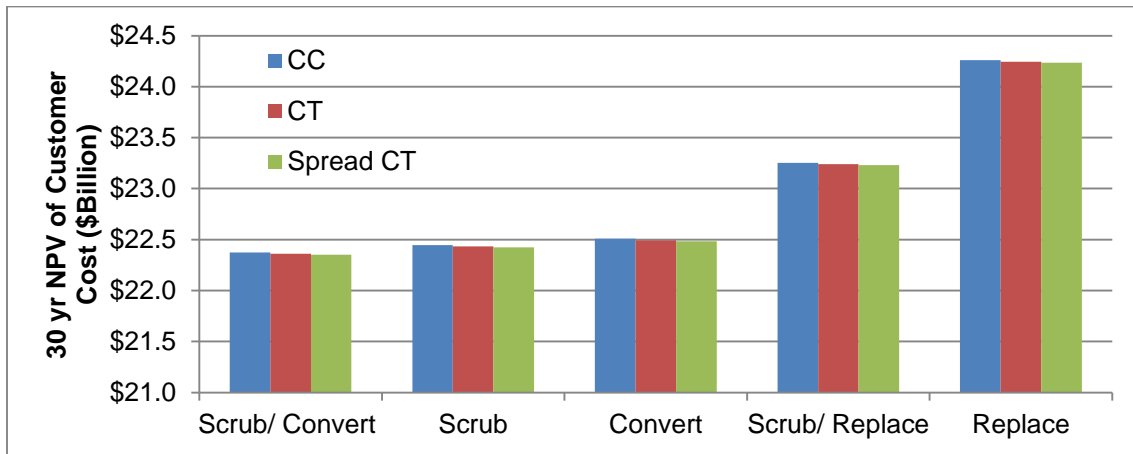
Figure 10: Customer Cost Components



a) Compliance Alternative and Expansion Plan Analysis

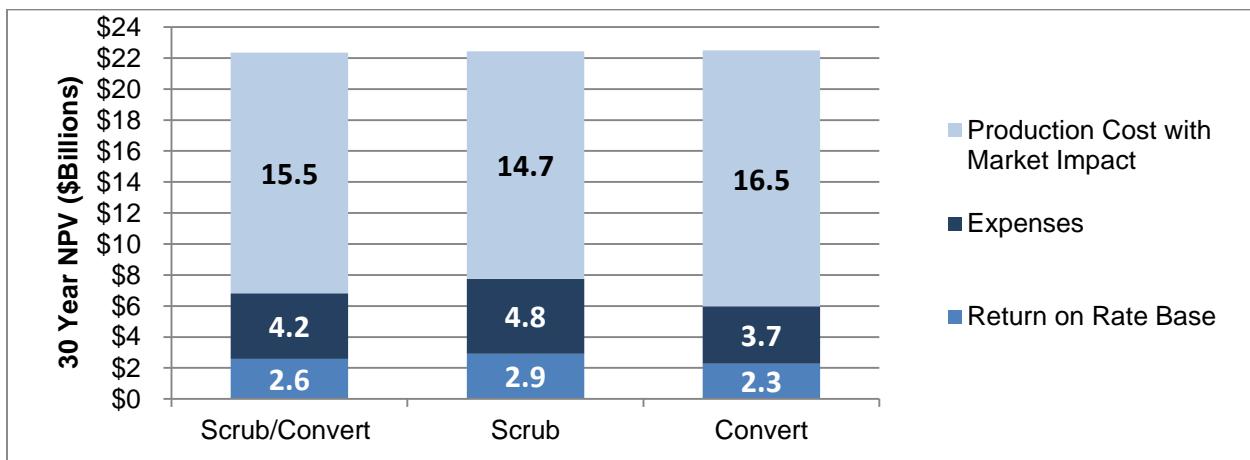
The results of the modeling are provided in a 30-year Net Present Value (“NPV”) of customer costs format for each compliance alternative and expansion plan in Figure 11.

**Figure 11: Compliance Alternative and Expansion Plan Comparison
(2014 \$Billions)**



As shown in this figure, the “Replace” alternatives are considerably more expensive than the “Convert” alternatives. The “Scrub” and “Convert” alternatives are relatively close (as well as the combined “Scrub/Convert” alternative). There is also minimal difference among the three expansion options although they are consistently ranked from lowest cost to highest cost as follows: Spread CT, CT, and CC. The expansion options do not appear to influence the comparison among environmental compliance alternatives. For the remaining analysis shown in this report, the Spread CT expansion plan will be used since it is the least cost option. To better understand the dynamics between compliance alternatives it is helpful to consider the customer cost components of the three lowest cost compliance alternatives as identified in Figure 12.

**Figure 12: Cost Component Comparison for Select Compliance Alternatives
(2014 \$Billions)**



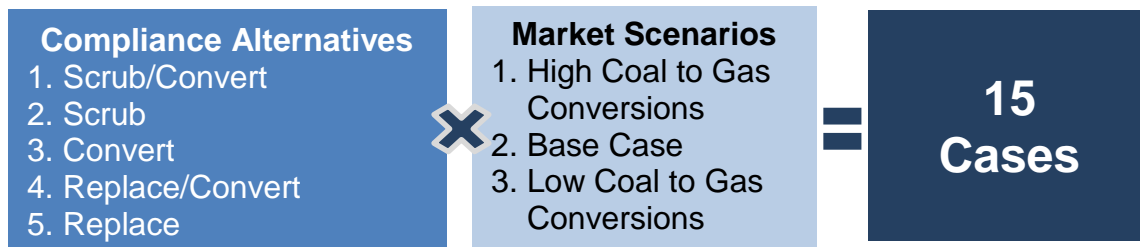
As shown, the alternatives that include scrubbing have higher return on rate base and expenses but lower production cost with market impact. The lower production cost with market impact reflects the margins that customers receive from OG&E selling coal generation into the market. The alternatives that include converting coal to natural gas have lower return on rate base and expenses but higher production cost with market impacts because OG&E has less coal generation to sell into the market. Comparing the production cost with market impact of the three compliance alternatives illustrates the value of coal generation as compared to market prices.

The next step in the analysis is to consider how these portfolios perform when subject to different IM price scenarios and sensitivity analyses around fuel prices, carbon prices, load forecast and capital costs.

b) Scenario Analysis

As described in Section III, OG&E developed three market scenarios that were defined to capture the uncertainty of other SPP IM participant responses to environmental compliance requirements with respect to their coal units. OG&E’s compliance alternatives were tested in each market scenario to determine the impact that other market participants could have on decisions made by OG&E. The Spread CT expansion plan is used with each compliance alternative for the market scenario combinations illustrated in Figure 13.

Figure 13: Compliance Alternatives and Market Scenario Combinations



The 30-year NPV of customer costs for each compliance alternative in the scenario analysis is provided in Table 17.

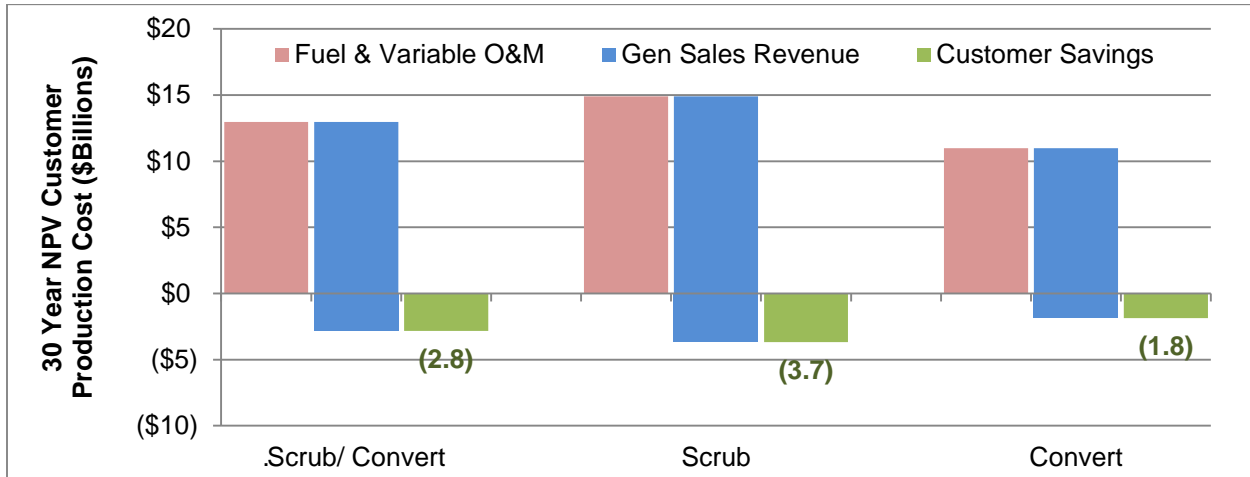
Table 17: Market Scenario 30-year NPVCC Values (2014 \$Billions)

| | Scrub/Convert | Scrub | Convert | Scrub/Replace | Replace |
|------------------------|---------------|--------|---------|---------------|---------|
| High Conversion | \$22.4 | \$22.3 | \$22.7 | \$23.0 | \$24.0 |
| Base Case | \$22.4 | \$22.4 | \$22.5 | \$23.2 | \$24.2 |
| Low Conversion | \$22.2 | \$22.4 | \$22.2 | \$23.3 | \$24.3 |

The “Convert” compliance alternative is impacted by a change in market prices by about \$0.5 billion (\$22.2 to \$22.7 billion) and is more than the other alternatives. Again, this is

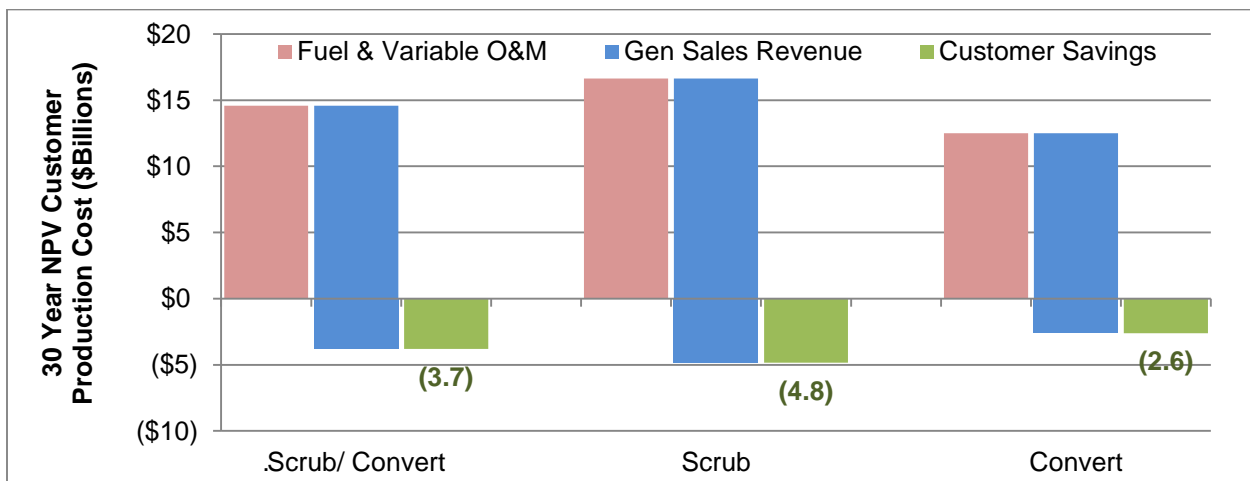
due to OG&E having less coal generation to sell into the SPP market or to hedge market prices due to diversification. This analysis has no impact on the return on rate base or fixed costs making it possible to focus more narrowly on production costs and generation revenue to compare the scenarios. The difference in production cost and generation revenue is the savings customers realize from owning low cost coal generation and is shown in Figure 14.

**Figure 14: Customers Production Cost in Base Case Market Scenario
(2014 \$Billions)**



In the Base Case market scenario the 30 year NPV customer production cost savings associated with the “Scrub” compliance alternative is \$1.9 billion more than the savings associated with the “Convert” compliance alternative. To demonstrate the impact of market prices on the NPV savings associated with compliance alternatives, the customer production cost in the High Conversion market scenario is shown in Figure 15.

**Figure 15: Customers Production Cost in High Conversion Market Scenario
(2014 \$Billions)**

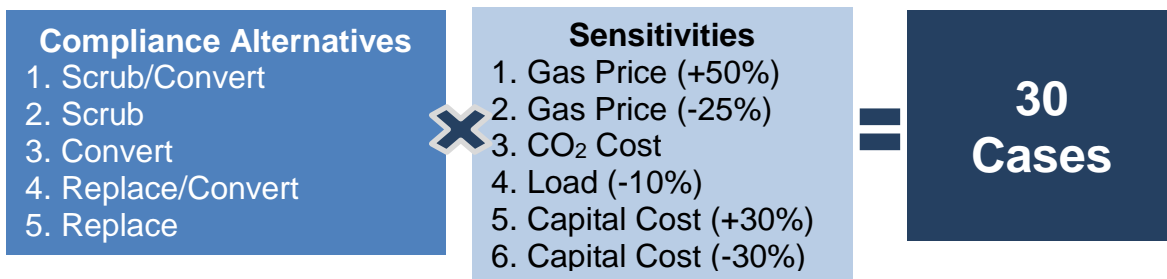


In the high conversion market scenario the 30-year NPV customer production cost savings associated with the “Scrub 4” compliance alternative jumps to \$2.2 billion more than the savings associated with the “Convert 4” compliance alternative. Comparing the two charts it is clear that the scrub alternatives offer increased savings as market prices increase and thus provide a hedge against higher market prices due to diversification.

c) Sensitivity Analyses

Sensitivity analysis involves changing a single input variable of the Base Case and measures the impact of the change in that specific variable. The variables changed in the sensitivity analyses are the Natural Gas Prices, Load for SPP members, CO₂ Prices and capital cost of emission control technologies as described in section III. The Spread CT expansion plan is used with each compliance alternative for sensitivities illustrated in Figure 16.

Figure 16: Sensitivity Development



The 30-year NPV of customer costs for each case in the sensitivity analysis is provided in Table 18.

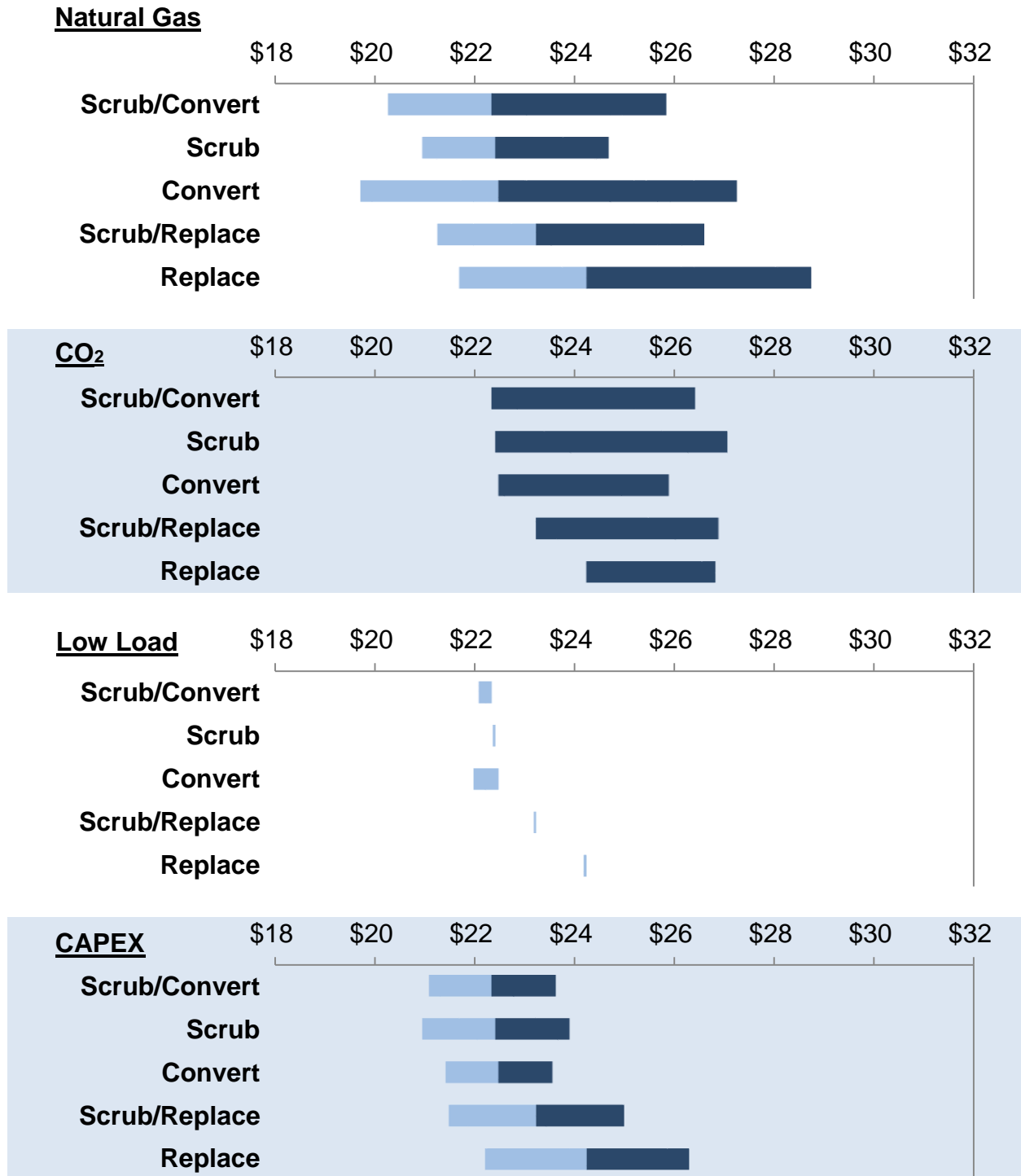
Table 18: Sensitivity 30-year NPVCC Values (2014 \$Billions)

| | Scrub/ Convert | Scrub | Convert | Scrub/ Replace | Replace |
|--------------------------|-------------------|--------|---------|-------------------|---------|
| High Gas | \$25.8 | \$24.7 | \$27.2 | \$26.6 | \$28.7 |
| Low Gas | \$20.3 | \$21.0 | \$19.7 | \$21.3 | \$21.7 |
| CO₂ | \$26.4 | \$27.0 | \$25.9 | \$26.9 | \$26.8 |
| Low Load | \$22.1 | \$22.4 | \$22.0 | \$23.2 | \$24.2 |
| High Capital Cost | \$23.6 | \$23.9 | \$23.6 | \$25.0 | \$26.3 |
| Low Capital Cost | \$21.1 | \$21.0 | \$21.4 | \$21.5 | \$22.2 |

As expected, compliance alternatives that rely on converting from coal to natural gas are impacted by gas price sensitivity the most and compliance alternatives that rely on scrubbing coal units are impacted by gas price sensitivity the least. The reverse is true for CO₂ price sensitivity as a carbon tax would hit coal unit costs the hardest. Low load has very little impact on all compliance alternatives though the largest impact is on the convert alternative since lower load in SPP would free up low cost generation in the

market resulting in reduced load costs. Sensitivity to capital costs has a relatively low impact as compared to natural gas and CO₂ price sensitivity but it does have the greatest impact on the scrub compliance alternatives as they have a higher capital cost. The tornado charts in Figure 17 present the range of customer costs for each compliance alternative using the base case scenario as a starting point.

Figure 17: Sensitivity Analysis NPVCC (2014 \$Billions)



3. Lowest Reasonable Cost Plan

Given the relatively modest differences among the three lower-cost environmental compliance alternatives and the varying results of the CO₂ and gas price sensitivities, OG&E concludes that the Scrub/Convert alternative offers the lowest reasonable cost. This determination was based on the least cost/risk plan that best meets the comprehensive list of objectives identified by OG&E. This is an appropriate conclusion despite the fact that the Scrub/Convert is not the lowest cost plan in any of the six sensitivity cases presented in Table 20. Rather, it is the second lowest cost option in all six cases, whereas the Scrub and Convert options have a lower cost than the Replace options in all of the cases. In order to operate Muskogee 4 and 5 as gas units a natural gas pipeline into the Muskogee plant will need to be constructed. OG&E expects that through a competitive bidding process a third party would construct the pipeline and charge a transportation fee for the service.

It should also be noted that acquisition of an existing 500 MW combined-cycle plant could be an alternative to the conversion of a Muskogee unit. OG&E has acquired two existing combined-cycle plants over the past decade (McClain and Redbud) and continues to monitor CC plants across the SPP region. However, it should also be noted that our analysis indicates that the 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 new highly efficient plant. Older CC plants with higher heat rates would make sense only at lower acquisition costs. Thus, it appears that it isn’t a viable alternative as OG&E believes no combined cycle plants are available at the acquisition cost necessary make this alternative economical.

Overall, the lowest reasonable cost plan is the Scrub/Convert compliance alternative with Spread CT expansion plan. This portfolio provides the best overall performance when measured against the set of IRP objectives.

C. Wind Energy Analysis

OG&E considered including wind generation as an element of the environmental compliance plan analysis but determined that it would not add any incremental insights that would affect the analysis or recommendation. The primary objective of the environmental compliance plan is the absolute requirement that OG&E replace the capacity provided by the existing coal units with a like amount of capacity in order to meet its load obligations. SPP recognizes 5% of nameplate wind generation capability for capacity margin purposes for wind generation under 3 years of operation. This implies that 10,000 MW of wind would be needed to replace just one of OG&E’s 500 MW coal units. Therefore, wind generation would not serve as an effective resource to address the planning capacity needs in OG&E’s environmental compliance plan.

Additionally, OG&E considered wind energy from a customer savings perspective. Prior to the SPP IM, OG&E either generated wind energy or purchased wind energy through purchased power agreements. This energy was used to directly serve OG&E’s customers and the cost of the wind energy was passed through to customers. In the

SPP IM, the entire pool (including OG&E customers) proportionately pays the market price for each individual wind facility as determined by the SPP economic dispatch model regardless of the wind energy provider's cost. The wind energy provider (or its customers) bears the price risk between its costs and the market price as determined by SPP.

Another change created by the SPP IM is that wind developers may now construct wind farms and sell the energy output directly into the SPP IM without an agreement with OG&E. While analysis indicates that wind energy may provide energy cost savings over a 25 year period, these savings are dependent on assumed SPP IM prices. Based on recent experience with wind energy there is considerable SPP IM price risk. OG&E expects 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. In the interim, we are supportive of wind developers constructing new wind farms and selling the energy directly into the SPP IM.

This does not imply that wind energy will not continue to serve a critical role in OG&E's portfolio and indeed it is likely that OG&E will increase its reliance on wind energy over the coming decade, particularly after transmission constraints are relieved. The fact is that wind technology and associated capital costs are continuing to improve and may indeed reach levels where wind energy tax credits are no longer necessary to support growth in wind energy.

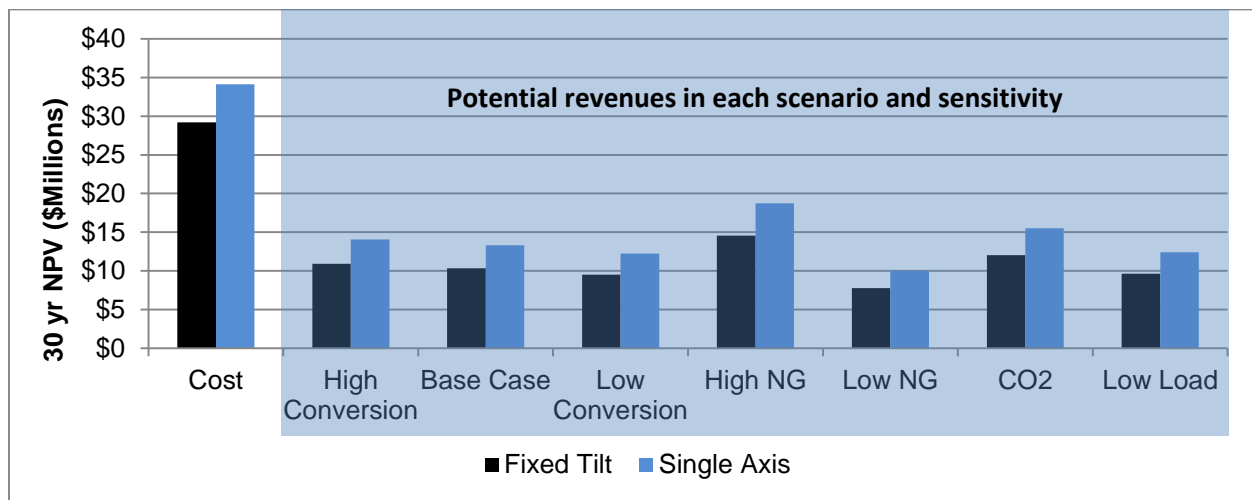
On May 18, 2015, OG&E issued a wind RFI to gain market intelligence of wind energy pricing and availability. OG&E continues to analyze the wind responses including conducting congestion and market revenue studies.

D. Central Solar Analysis

Combining the costs of the investment and future maintenance expenses, the 30-year net present value of the cost of 10 MW of central solar is around \$35 million. This cost can then be compared to the expected revenues from the solar unit operating in the various market price scenarios and sensitivities. As shown in Figure 18, the cost of solar is about twice the amount of the potential revenues, confirming that central solar is not a viable option for OG&E at this time.

However, OG&E continues to study solar through its recent project at the Mustang site and through analysis of responses received from a recent RFI for Solar Energy.

Figure 18: Potential Revenue and Cost (2014 \$Millions)



E. Conclusions from Resource Planning Analysis

Based on this resource planning analysis, OG&E has determined that the following strategy will provide the greatest benefits to OG&E's customers:

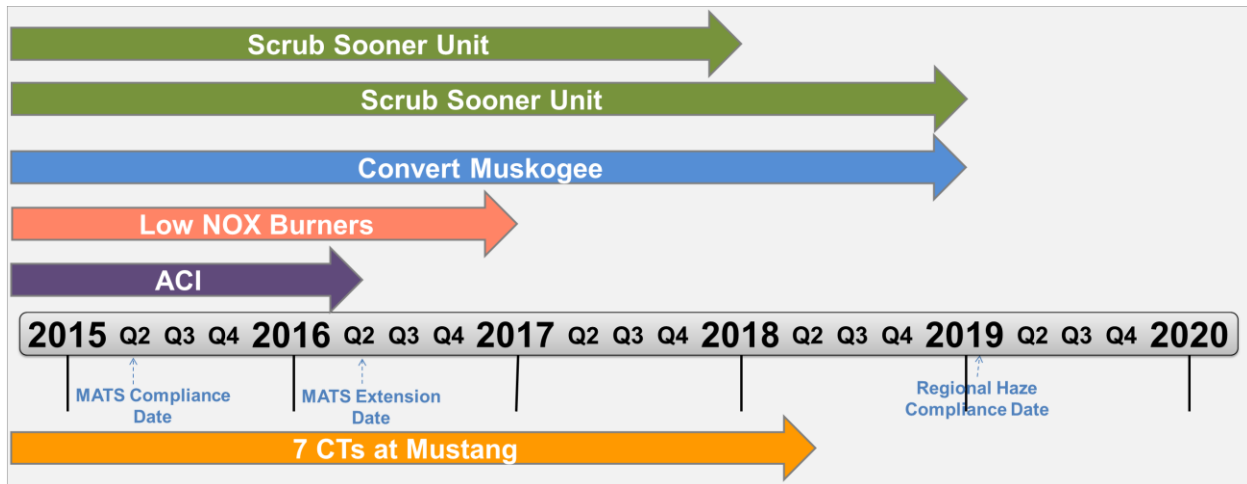
- (1) Continue to aggressively pursue demand-side resources;
- (2) Scrub Sooner Units 1 and 2;
- (3) Convert Muskogee 4 and 5 to natural gas;
- (4) Replace Mustang Units 1-4 (463MW) with 400MW of natural-gas fired combustion turbines; and
- (5) Evaluate responses to the 2015 RFIs to determine the value and viability of wind, solar, and thermal resources in the SPP IM.

When considered as a comprehensive resource plan, this combination of actions addresses OG&E's future requirements in a lowest reasonable cost manner and leverages prior OG&E actions that have been made while it implemented the 2020 Goal.

VI. RESOURCE STRATEGY AND ACTION PLAN

The Five-Year Action Plan addresses the years from 2015 to 2019. Within this time frame, OG&E will be making modifications to a number of units to maintain compliance with environmental regulations.

Figure 19: Action Plan Timeline



Regional Haze compliance date is set 55 months from US Supreme Court decision.
 Clock restarted 5/29/2014 + 55 months = 1/4/2019

A. Environmental Controls

1. Activated Carbon Injection

The installation of ACI equipment for mercury removal is planned to be complete on all coal units by April 2016.

2. Low NO_x Burners

By early 2017, OG&E plans to complete installation of Low NO_x burners with overfire air on seven units (Muskogee 4 & 5, Sooner 1 & 2, Seminole 1, 2 & 3) to reduce emissions that cause or contribute to regional haze. Installation has been completed on Muskogee unit 5 and Sooner units 1 and 2.

3. Dry Scrubbers at Sooner

Dry scrubbers for SO₂ removal will be installed on Sooner 1 by 2018 and Sooner 2 by 2019. OG&E believes the installation of dry scrubbers will keep the Sooner plant in compliance with the federal requirements for SO₂ emissions.

4. Convert Muskogee 4 & 5 to Natural Gas

Muskogee 4 & 5 will be converted to natural gas by 2019. OG&E believes the conversion from coal to natural gas will satisfy the federal requirements for SO₂ emissions.

B. Mustang Unit Retirement and Replacement Units

OG&E plans to retire the existing Mustang units by the end of 2017. Prior to the 2018 summer peak OG&E plans to install seven (7), 57 MW units at a cost of approximately of \$400 million.

C. Demand Side Management Plan

OG&E plans to continue to expand Energy Efficiency programs and expects growth in Demand Response programs. OG&E depends on the Demand Side Management plan to maintain an adequate planning capacity margin in SPP and to achieve the “2020 Goal.”

D. Future Generation Options

OG&E will continue to monitor market conditions and implementation feasibility of generation options. In the fall of 2015, OG&E will evaluate responses to its RFI for fossil fuel generation capacity along with renewable (solar and wind) generation.

VII. SCHEDULES

This section is intended to provide a tabular summary of each section as described in the OCC's Electric Utility Rules, Subchapter 37 of Chapter 35, section 4 (c).

Schedule A – Electric Demand and Energy Forecast

Details of this forecast can be found starting on page 19 and also in Appendix A – OG&E 2015 Load Forecast.

OG&E Energy Sales Forecast (GWh)

| GWh | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---------------------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| Retail Energy | 29,628 | 29,950 | 30,218 | 30,477 | 30,756 | 30,993 | 31,203 | 31,434 | 31,676 | 31,936 |
| OG&E DSM | 461 | 563 | 672 | 773 | 869 | 970 | 1,065 | 1,153 | 1,244 | 1,332 |
| Load Responsibility | 29,167 | 29,387 | 29,547 | 29,703 | 29,887 | 30,023 | 30,138 | 30,281 | 30,431 | 30,604 |
| Retail Growth | | 0.76% | 0.54% | 0.53% | 0.62% | 0.46% | 0.38% | 0.48% | 0.50% | 0.57% |

OG&E Peak Demand Forecast (MW)

| MW | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---------------------|-------|-------|--------|-------|-------|-------|-------|-------|-------|-------|
| Retail Demand | 6,265 | 6,344 | 6,388 | 6,437 | 6,469 | 6,532 | 6,566 | 6,611 | 6,636 | 6,698 |
| OG&E DSM | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |
| Load Responsibility | 5,898 | 5,916 | 5,900 | 5,924 | 5,931 | 5,968 | 5,978 | 6,000 | 6,001 | 6,041 |
| Retail Growth | | 0.32% | -0.27% | 0.41% | 0.12% | 0.62% | 0.17% | 0.37% | 0.01% | 0.67% |

Forecasted Energy Reduction from DSM (GWh)

| GWh | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------------------|------|------|------|------|------|------|-------|-------|-------|-------|
| Current Portfolio | 318 | 318 | 318 | 317 | 316 | 313 | 307 | 300 | 293 | 285 |
| 2016 Portfolio: EE | 94 | 191 | 294 | 294 | 294 | 293 | 292 | 290 | 286 | 281 |
| 2019 Portfolio: EE | - | - | - | 101 | 198 | 301 | 301 | 301 | 300 | 299 |
| 2022 Portfolio: EE | - | - | - | - | - | - | 101 | 198 | 301 | 301 |
| 2025 Portfolio: EE | - | - | - | - | - | - | - | - | - | 101 |
| IVVC | 25 | 29 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| LRR | 3 | 4 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 |
| Smart Hours | 21 | 21 | 22 | 23 | 23 | 24 | 25 | 25 | 25 | 26 |
| Total Net Energy Reduction | 461 | 563 | 672 | 773 | 869 | 970 | 1,065 | 1,153 | 1,244 | 1,332 |

Forecasted Peak Demand Reduction from DSM (MW)

| MW | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------------------|------|------|------|------|------|------|------|------|------|------|
| Current Portfolio | 81 | 81 | 81 | 81 | 80 | 79 | 78 | 76 | 74 | 72 |
| 2016 Portfolio: EE | 20 | 42 | 66 | 66 | 66 | 66 | 65 | 65 | 64 | 63 |
| 2019 Portfolio: EE | - | - | - | 22 | 44 | 68 | 68 | 68 | 67 | 67 |
| 2022 Portfolio: EE | - | - | - | - | - | - | 22 | 44 | 68 | 68 |
| 2025 Portfolio: EE | - | - | - | - | - | - | - | - | - | 22 |
| IVVC | 54 | 67 | 82 | 82 | 82 | 82 | 82 | 82 | 82 | 82 |
| LRR | 62 | 88 | 109 | 112 | 116 | 119 | 123 | 126 | 130 | 133 |
| Smart Hours | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| Total Net Demand Reduction | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |

Schedule B – Existing Resources

This schedule provides a summary of existing supply side resources. Details on this data can be found in the Resource Options section starting on page 23.

OG&E Existing Generation Resources – 2016 Peak Planning Capacity

| Unit Type | Unit Name | First Year In Service | Capacity (MW) |
|--|-----------------------|-----------------------|---------------|
| Coal Fired Steam (2,516 MW) | Muskogee 4 | 1977 | 487 |
| | Muskogee 5 | 1978 | 503 |
| | Muskogee 6 | 1984 | 485 |
| | Sooner 1 | 1979 | 521 |
| | Sooner 2 | 1980 | 520 |
| Gas Fired Steam (2,492 MW) | Horseshoe Lake 6 | 1958 | 166 |
| | Horseshoe Lake 8 | 1969 | 411 |
| | Mustang 1 | 1950 | 0 |
| | Mustang 2 | 1951 | 51 |
| | Mustang 3 | 1955 | 117 |
| | Mustang 4 | 1959 | 257 |
| | Seminole 1 | 1971 | 492 |
| | Seminole 2 | 1973 | 500 |
| Combined Cycle (1,205 MW) | Seminole 3 | 1975 | 498 |
| | Horseshoe Lake 7 | 1963 | 221 |
| | McClain | 2001 | 376** |
| Quick Start Combustion Turbine (157 MW) | Redbud | 2002 | 608** |
| | Horseshoe Lake 9 | 2000 | 45 |
| | Horseshoe Lake 10 | 2000 | 45 |
| | Mustang 5A | 1971 | 34 |
| | Mustang 5B | 1971 | 33 |
| Purchase Power - Thermal (440 MW) | Seminole 1GT | 1971 | 0 |
| | AES Shady Point | 1990 | 320 |
| Purchase Power - Wind (20 MW) | Oklahoma Cogeneration | 1989 | 120 |
| | FPL Wind | 2003 | 4 |
| | Keenan | 2010 | 9 |
| | Taloga | 2011 | 2 |
| Owned Wind (31 MW) | Blackwell | 2012 | 5 |
| | Centennial | 2007 | 16 |
| | OU Spirit | 2009 | 5 |
| Total Net Capability | | | 6,861 |

** Represents OG&E owned interest.

Emission Control Technologies (2015 dollars)

| Control | Units | Overnight Capital Cost (\$Millions) | Fixed O&M Cost (\$Millions) | Variable O&M Cost (\$/MWh) |
|-----------------------------|-------------------|-------------------------------------|-----------------------------|----------------------------|
| Dry Scrubber | All Coal per unit | \$245.0 | \$7.94 | \$2.75 |
| Low NO _x Burners | Muskogee 4 | \$9.3 | \$0.24 | - |
| Low NO _x Burners | Sooner 1 | \$11.9 | \$0.24 | - |
| Low NO _x Burners | Seminole 1&2 | \$43.1 | \$1.31 | - |
| Low NO _x Burners | Seminole 3 | \$19.6 | \$0.65 | - |
| Activated Carbon Injection | All Coal | \$22.7 | \$0.81 | \$2.52 |
| Conversion to Gas | Muskogee per unit | \$38.0 | (\$5.62) | (\$0.12) |
| Conversion to Gas | Sooner per unit | \$38.0 | (\$5.80) | \$0.39 |

*Represents the incremental cost decrease due to conversion from coal to gas

Schedule C – Transmission Capability and Needs

Section IV.C on page 31 provides a description of OG&E transmission system. The table below shows how many miles of transmission OG&E has by transmission voltage.

Transmission Lines by Voltage (Miles)

| Voltage | 69 kV | 138kV | 161 kV | 345 kV | 500 kV | Total |
|---------|-------|-------|--------|--------|--------|-------|
| Miles | 1,413 | 1,910 | 252 | 1,087 | 47 | 4,709 |

Schedule D – Needs Assessment

This schedule provides the needs assessment for new generating resources for the next 10 years. A further description of these needs is found on page 38.

Planning Capacity Margin (MW unless noted)

| | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------|---------------------------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| Resources | Total Owned Capacity | 6,401 | 6,401 | 5,977 | 5,977 | 5,977 | 5,977 | 5,977 | 5,977 | 5,811 | 5,811 |
| | Purchase Contracts | 460 | 460 | 460 | 456 | 336 | 336 | 336 | 16 | 16 | 16 |
| | Total Net Dependable Capability | 6,861 | 6,861 | 6,437 | 6,433 | 6,313 | 6,313 | 6,313 | 5,993 | 5,827 | 5,827 |
| Demand | Demand Forecast | 6,265 | 6,344 | 6,388 | 6,437 | 6,469 | 6,532 | 6,566 | 6,611 | 6,636 | 6,698 |
| | OG&E DSM | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |
| | Net Demand | 5,898 | 5,916 | 5,900 | 5,924 | 5,931 | 5,968 | 5,978 | 6,000 | 6,001 | 6,041 |
| Capacity Needs | Capacity Margin | 963 | 945 | 536 | 508 | 381 | 345 | 334 | (8) | (174) | (215) |
| | Percent Capacity Margin (%) | 14.0 | 13.8 | 8.3 | 7.9 | 6.0 | 5.5 | 5.3 | (0.1) | (3.0) | (3.7) |
| | Needed Capacity | - | - | 269 | 300 | 428 | 470 | 481 | 826 | 993 | 1,039 |

Schedule E – Resource Options

This schedule provides a description of the supply side options available to OG&E to address the needs identified in Schedule D and further explained starting on page 28.

New Supply Side Resources (2015 Dollars)

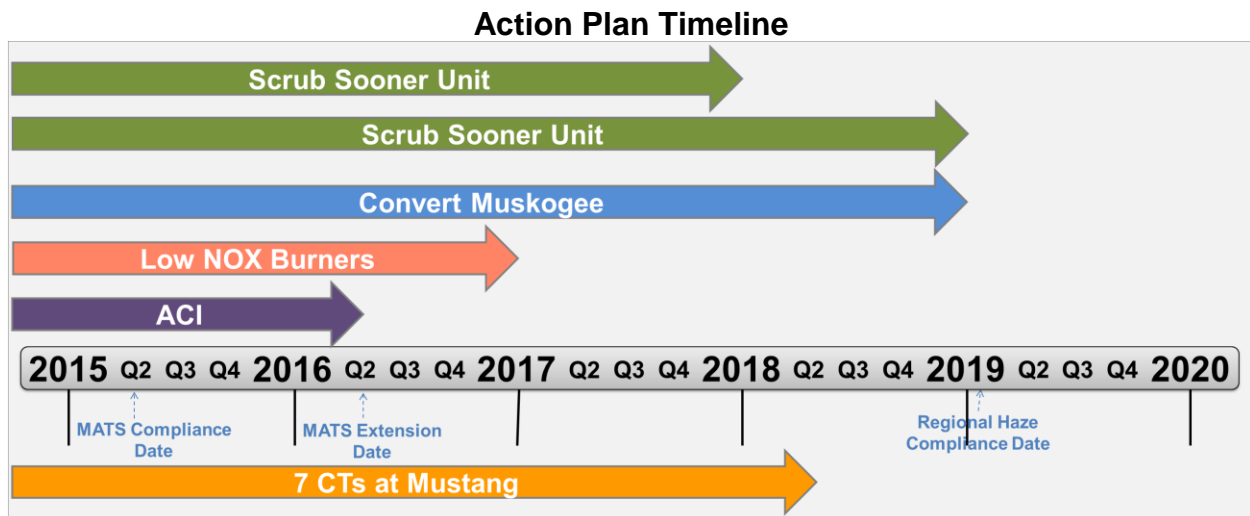
| Type | Technology | Net Capacity (MW) | Heat Rate (Btu/kWh) | Overnight Capital Cost (\$/kW) | Fixed O&M Cost (\$/kW) | Variable O&M Cost (\$/MWh) |
|--------------------|--------------------|-------------------|---------------------|--------------------------------|------------------------|----------------------------|
| Natural Gas | Combined Cycle | 281 | 6,120 | \$1,499 | \$22.87 | \$2.60 |
| | Combined Cycle | 562 | 6,120 | \$1,247 | \$16.63 | \$2.60 |
| | Combustion Turbine | 39 | 8,904 | \$1,019 | \$27.02 | \$1.84 |
| | Combustion Turbine | 75 | 10,733 | \$1,102 | \$22.87 | \$18.71 |
| | Combustion Turbine | 86 | 8,309 | \$1,684 | \$16.63 | \$4.57 |
| | Combustion Turbine | 237 | 9,040 | \$1,001 | \$8.32 | \$16.63 |

Schedule F – Fuel Procurement and Risk Management Plan

On May 15, 2015, OG&E filed its annual Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. The filed document can be found at the OCC.

Schedule G – Action Plan

This schedule outlines the proposed actions for the next five years. These actions are in accord with this IRP, and will position OG&E to complete the plan as described in this report. The Five-Year Action Plan addresses the years from 2015 to 2019. Within this time frame, OG&E will be making modifications to a number of units to maintain compliance with environmental regulations.



Regional Haze compliance date is set 55 months from US Supreme Court decision. Clock restarted 5/29/2014 + 55 months = 1/4/2019

Environmental Controls

Activated Carbon Injection

The installation of Activated Carbon Injection (ACI) equipment for mercury removal is planned to be complete on all coal units by April 2016.

Low NO_x Burners

By early 2017, OG&E plans to complete installation of Low NO_x burners with overfire air on seven units (Muskogee 4 & 5, Sooner 1 & 2, Seminole 1, 2 & 3) to reduce emissions that cause or contribute to regional haze. Installation has been completed on Muskogee unit 5 and Sooner units 1 and 2.

Dry Scrubbers at Sooner

Dry scrubbers for SO₂ removal will be installed on Sooner 1 by 2018 and Sooner 2 by 2019. OG&E believes the installation of dry scrubbers will keep the Sooner plant in compliance with the federal requirements for SO₂ emissions.

Convert Muskogee 4 & 5 to Natural Gas

Muskogee 4 & 5 will be converted to natural gas by 2019. OG&E believes the conversion from coal to natural gas will satisfy the federal requirements for SO₂ emissions.

Mustang Unit Retirement and Replacement Units

OG&E plans to retire the existing Mustang units by the end of 2017. Prior to the 2018 summer peak OG&E plans to install seven (7), 57 MW units at a cost of approximately of \$400 million.

Demand Side Management Plan

OG&E plans to continue to expand Energy Efficiency programs and expects growth in Demand Response programs. OG&E depends on the Demand Side Management plan to maintain an adequate planning capacity margin in SPP and to achieve the “2020 Goal.”

Future Generation Options

OG&E will continue to monitor market conditions and implementation feasibility of generation options. In the fall of 2015, OG&E will evaluate responses to its RFI for fossil fuel generation capacity along with renewable (solar and wind) generation.

Schedule H – Requests for Proposals

OG&E has already conducted Requests for Proposals (“RFPs”) for all control equipment associated with the Low NO_x burners in the seven units impacted by Regional Haze Rules (RHR) and contracts were awarded to the lowest evaluated bidder. Installation of these burners is complete on all four RHR affected OG&E coal units (Sooner units 1 and 2. Muskogee Units 4 and 5). The contracts for these installation services were

awarded based on competitive bidding. Installation of low NOx burners on the three remaining RHR affected units (Seminole Units 1, 2 &3) will begin this fall. Unit 2 installation is under contract and was awarded via competitive bidding. Installation on Units 1 and 3 will also be competitively bid as those projects near execution.

Material, equipment and installation services for dry scrubbers at Sooner to comply with the SO2 reductions under the RHR are under contract and were awarded by virtue of competitive bidding.

Also awarded under competitive bidding were all contracts for materials and installation for Activated Carbon Injection on all five OG&E coal units impacted by the MATS rule.

In addition, OG&E intends to conduct RFPs for the equipment and work associated with the conversion of the Muskogee Units closer to the 2019 conversion date specified under the SO2 portion of the RHR Federal Implementation Plan (FIP).

Combustion turbines for the new Mustang units in the Mustang Modernization Plan (MMP) were purchased under contracts that were competitively bid. Installations packages and balance of plant equipment will also be purchased under a number of competitively awarded contracts as sufficient engineering is completed to support these bid events.

OG&E will make the RFP documents and procedures for the low NOx burners, scrubbers and ACI available upon request and subject to the Protective Order issued in Cause No. PUD201400137.

Schedule I – Modeling Methodology and Assumptions

This schedule is a technical appendix for the data, assumptions, and descriptions of models needed to understand the derivation of the resource plan. The table below explains who supplied each assumption and provides a reference for where this information is found in the IRP. Since the load forecast is provided in Appendix A, the remaining was provided in Schedule A, it has not been repeated here.

| Assumption | Source | Page |
|-------------------------------------|-----------|------|
| Load | OG&E | 19 |
| DSM | OG&E | 20 |
| Existing Unit Characteristics | OG&E | 23 |
| Emission Control Technologies | OG&E, S&L | 27 |
| New Resource Screening Requirements | OG&E, EIA | 28 |
| New Unit Characteristics | OG&E, S&L | 30 |
| Natural Gas | EIA | 34 |
| Coal | EIA | 34 |
| CO ₂ | OG&E | 34 |
| Market Prices | OG&E | 34 |

Descriptions of Software Tools

OG&E utilizes two software programs for production cost modeling.

GenTrader®

The GenTrader® software provided by Power Costs, Inc. is designed to model complex portfolios of power and fuel resources, including generators, contracts, options, and ancillary services in great detail. Some of the functionalities include: multiple and concurrent fuel and emission limits, multi-stage combined-cycle modeling, ancillary services like regulations and spinning reserve as well as energy limited contracts. GenTrader® is used to simulate OG&E owned or contracted units serving OG&E's load

PROMOD IV®

The PROMOD IV® software provided by Ventyx is the industry-leading Fundamental Electric Market Simulation software, incorporating extensive details in generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations. PROMOD IV® is used to model the SPP Integrated Marketplace.

Schedule J – Transmission System Adequacy

This schedule is a description of the transmission system adequacy over the next 10 years. SPP evaluates system adequacy and develops a transmission expansion plan to determine what improvements are necessary to ensure reliable transmission service. The 2015 SPP Transmission Expansion Plan¹⁰ describes improvements necessary for regional reliability, local reliability, generation interconnection, long-term tariff studies due to transmission service requests and transmission owner sponsored improvements. Included in below is a subset of the 2015 STEP, which OG&E has committed to construct.

Estimated Capital Expenditures for OG&E Committed Projects

| Year | Description | Type of Upgrade | Cost Allocation | Cost (\$Million) | Facility Owner |
|--------|---------------------------------|-----------------------|----------------------|------------------|----------------|
| 1 2015 | Little River to Maud Tap 69 KV | Reconductor Line | High Priority | \$6.4 | TBD |
| 2 2015 | Renfrow to Medford Tap 138 KV | New Line | Regional Reliability | \$3.2 | OGE |
| 3 2015 | Medford Tap to Doolin 138 KV | New Line | Regional Reliability | \$13.8 | OGE |
| 4 2015 | Chikaskia to Doolin 138 KV | New Line | Regional Reliability | \$8.2 | OGE |
| 5 2015 | Doolin 138 KV Switching Station | New Substation | Regional Reliability | \$3.0 | OGE |
| 6 2015 | Ahloso to Harden City 69 KV | Convert Line 69 KV to | ITP | \$6.9 | OGE |

¹⁰ 2015 STEP http://www.spp.org/publications/2015_STEP_Report.pdf

| Year | Description | Type of Upgrade | Cost Allocation | Cost (\$Million) | Facility Owner |
|------|--|------------------------------------|----------------------------|------------------|----------------|
| | to 138 KV | 138 KV | | | |
| 7 | 2015 Frisco to Lula 69 KV to 138 KV | Convert Line 69 KV to 138 KV | ITP | \$6.7 | OGE |
| 8 | 2015 Alva 69 KV | Substation Upgrade | High Priority | \$0.2 | OGE |
| 9 | 2015 New Substation for GEN-2012-040 | New Substation | Generation Interconnection | \$3.0 | TBD |
| 10 | 2015 Four Corners 69 KV | New Capacitor | ITP | \$0.6 | OGE |
| 11 | 2015 Warner Tap 69 KV | Substation Upgrade | ITP | \$0.5 | OGE |
| 12 | 2015 Woodward EHV 345 KV for GEN-2007-062 | Substation Upgrade | Generation Interconnection | \$2.7 | OGE |
| 13 | 2015 New Windfarm at Beaver County 345 KV Substation | Substation Upgrade | Generation Interconnection | \$2.5 | OGE |
| 14 | 2015 New Windfarm at Matthewson 345 KV Substation | Substation Upgrade | Generation Interconnection | \$2.6 | OGE |
| 15 | 2016 Spring Valley Tap to Warwick 138 KV | New Line and Substation | High Priority | \$12.8 | OGE |
| 16 | 2016 Roman Nose to Darlington 138 KV | New Line | High Priority | \$12.7 | OGE |
| 17 | 2017 Ft. Smith Substation | Install 3rd 500/161 KV Transformer | Transmission Service | \$14.0 | OGE |
| 18 | 2017 VBI Substation | Substation Upgrade | Transmission Service | \$0.1 | OGE |
| 19 | 2017 El Reno Substation 69 KV | Substation Upgrade | Transmission Service | \$0.0 | OGE |
| 20 | 2017 Wildhorse 69 KV | New Capacitor | ITP | \$0.7 | OGE |
| 21 | 2017 Ahloso to Park Lane 69 KV to 138 KV | Convert Line 69 KV to 138 KV | ITP | \$5.7 | OGE |
| 22 | 2017 Harden City to Frisco 69 KV to 138 KV | Convert Line 69 KV to 138 KV | ITP | \$2.1 | OGE |
| 23 | 2018 Chisholm to Gracemont 345 KV | New Line | ITP | \$43.9 | OGE |
| 24 | 2018 Linwood to Spring Valley Tap 138 KV | New Line | High Priority | \$9.9 | OGE |
| 25 | 2018 Knipe to Spring Valley Tap 138 KV | New Line | High Priority | \$8.2 | OGE |
| 26 | 2018 Alva OGE to Alva WFEC 69 KV | Reconductor Line | High Priority | \$1.1 | TBD |
| 27 | 2019 Bryant to Memorial 138 KV | Replace Wave Trap | Transmission Service | \$0.2 | OGE |
| 28 | 2019 Arcadia to Redbud 345 KV ckt 3 | New Line | Transmission Service | \$18.0 | OGE |
| 29 | 2019 Division Ave to Lakeside 138 KV | Rebuild Line | Regional Reliability | \$1.7 | OGE |

| Year | Description | Type of Upgrade | Cost Allocation | Cost (\$Million) | Facility Owner | |
|------|-------------|---|--------------------------------------|-------------------------|----------------|-----|
| 30 | 2019 | Lane to Knobhill 138 KV, Lane to Noel 138 KV | New Line and Substation | ITP | \$4.0 | OGE |
| 31 | 2019 | Hefner to Tulsa 138 KV | Reconductor Line | Transmission Service | \$1.1 | OGE |
| 32 | 2019 | Anadarko to Gracemont 138 KV | Reconductor Line | ITP | \$4.5 | OGE |
| 33 | 2019 | Cimarron to Draper 345 KV | Substation Upgrade | ITP | \$0.1 | OGE |
| 34 | 2019 | Stillwater Substation | Install New 138/69 KV Transformer | ITP | \$2.8 | OGE |
| 35 | 2019 | Stillwater Substation | Substation Upgrade | ITP | \$0.6 | OGE |
| 36 | 2021 | Woodward to Tatonga 345 KV ckt 2 | New Line | ITP | \$59.5 | OGE |
| 37 | 2021 | Tatonga to Matthewson 345 KV ckt2 | New Line | ITP | \$65.8 | OGE |
| 38 | 2021 | Matthewson to Cimarron 345 KV ckt 2 | New Line | ITP | \$32.9 | OGE |
| 39 | 2021 | Matthewson 345 KV Substation | New Substation | ITP | \$20.0 | OGE |
| 40 | 2021 | Border to Chisholm 345 KV | New Line | High Priority | \$0.7 | TBD |
| 41 | 2021 | Chisholm to Woodward Dist EHV 345 KV | New Line | High Priority | \$0.7 | TBD |
| 42 | 2022 | Park Lane to Seminole 138 KV | Substation Upgrade | ITP | \$0.1 | TBD |
| 43 | 2022 | Seminole to Vanoss 138 KV | Replace Wave Trap | High Priority | \$0.0 | TBD |
| 44 | 2023 | Clyde to Grant County 69 KV to 138 KV | Convert Line 69 KV to 138 KV | High Priority | \$8.2 | TBD |
| 45 | 2023 | Clyde to Four Corners 69 KV to 138 KV | Convert Line 69 KV to 138 KV | High Priority | \$5.6 | TBD |
| 46 | 2023 | Four Corners to Kremlin 69 KV to 138 KV | Convert Line 69 KV to 138 KV | High Priority | \$19.5 | TBD |
| 47 | 2023 | Kremlin to NE Enid 69 KV to 138 KV | Convert Line 69 KV to 138 KV | High Priority | \$0.0 | TBD |
| 48 | 2023 | Russet to Glasses 138 KV | Substation Upgrade | High Priority | \$0.0 | TBD |
| 49 | 2023 | Cleo 69 KV | New Capacitor | High Priority | \$0.7 | TBD |
| 50 | 2023 | Saline 69 KV | New Capacitor | High Priority | \$0.7 | TBD |

Transmission system expansion provides benefits to members throughout the SPP; therefore, the costs of all projects constructed in the SPP are shared through various cost allocation methods, depending on the type of project.

Schedule K – Resource Plan Assessment

This IRP assessed the need for additional resources to meet reliability, cost and price, environmental, and other criteria established by the OCC, the State of Oklahoma, the

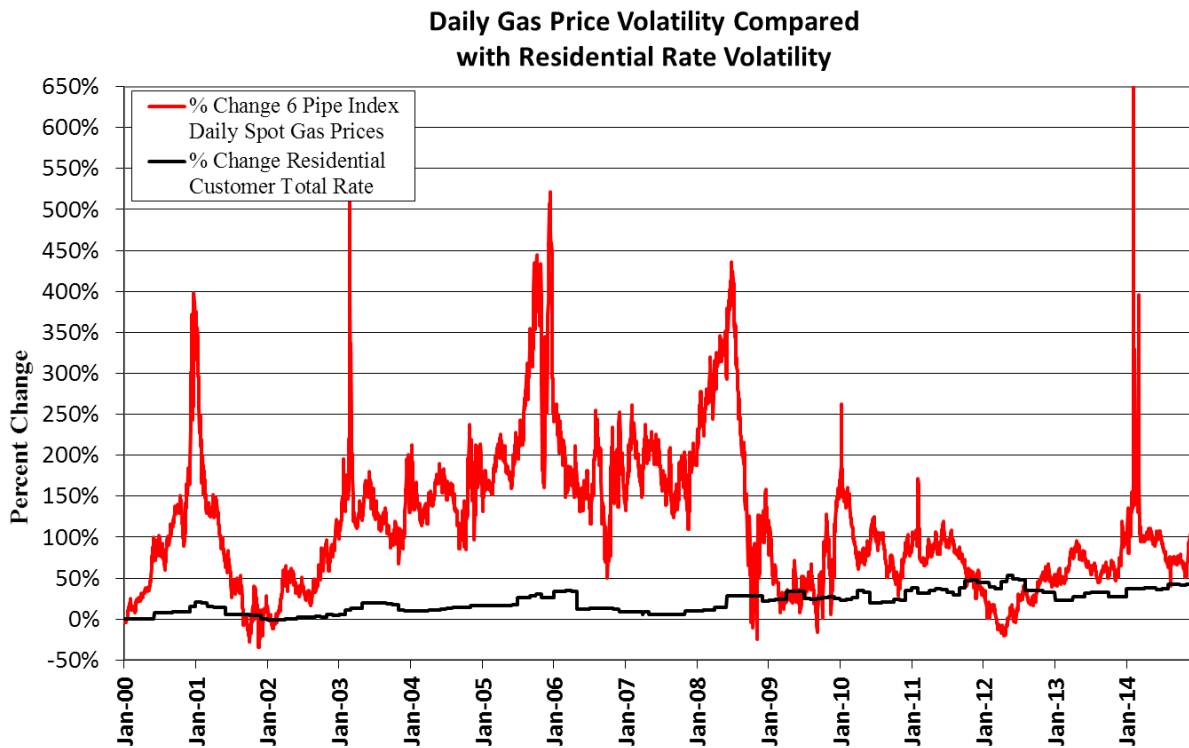
APSC, SPP, NERC, and FERC. All criteria were met by all portfolios considered in this IRP, in the base line condition. These criteria were also met in scenarios and uncertainties which included variations in load growth, fuel prices, emissions prices, environmental regulations, technology improvements, demand side resources, and fuel supply, among others. This plan provides a comprehensive analysis of the proposed options.

Schedule L – Proposed Resource Plan Analysis

This IRP demonstrates that all proposed alternatives meet all planning criteria as outlined in Schedule K. The proposed action plan outlined in Schedule G best meets these criteria. Documentation of the planning analysis and assumptions used in preparing this analysis are described in Schedule I.

Schedule M - Physical and Financial Hedging

OG&E’s Fuel Cost Adjustment tariff provides OG&E customers’ effective protection against fuel price volatility as shown below. Additionally, OG&E has a diverse mix of generation assets as outlined in Section IV of this report. The sensitivity analysis in Section V illustrates the advantages of generation diversity and the impact of the fuel volatility.



Note: 1. Base value for percentage changes is: 1/1/2000
 2. Fuel Adjustment Factors moved to coincide with operations month

Financial Hedging of a commodity such as power plant fuel is aimed at reducing the volatility in price. Financial hedging comes at a cost in the form of transaction costs, margin calls and premiums required to lock in pricing. OG&E's customers have been protected to a large extent from the historic volatility in natural gas prices by OG&E's portfolio approach to fuel and purchased power. As a result, the Company does not believe it to be prudent at this time to incur the additional costs associated with financial hedging.

On May 15, 2015, OG&E filed its annual Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. The filed document can be found at the OCC.

VIII. APPENDICES

Appendix A – OG&E 2015 Load Forecast



Final Report

2015 OG&E Load Forecast

Prepared by:
OGE Resource Planning Department

July 2015

Table of Contents

| | |
|---|----|
| Executive Summary | 1 |
| 1 Introduction | 5 |
| 2 Economic Outlook..... | 6 |
| 2.1 Economic Summary | 6 |
| 2.2 Underlying Economic Fundamentals | 6 |
| 2.2.1 Oklahoma Employment | 6 |
| 2.2.2 Oklahoma Energy Sector | 7 |
| 2.2.3 Consumer Spending..... | 7 |
| 2.2.4 Manufacturing Sector | 7 |
| 2.2.5 Real Estate and Construction..... | 7 |
| 2.3 Role of Economic Data in 2015 Energy Sales Forecast..... | 8 |
| 2.4 Economic Drivers for Energy Forecast | 8 |
| 3 OG&E Demand Side Management Summary..... | 9 |
| 4 Energy Forecast | 10 |
| 4.1 Econometric Modeling Process - Energy..... | 10 |
| 4.2 2015 Energy Forecast Adjustments..... | 11 |
| 4.2.1 National Energy Efficiency Adjustment..... | 11 |
| 4.2.2 Streetlight LED Implementation Adjustment..... | 13 |
| 4.2.3 FERC Wholesale Load Adjustments | 14 |
| 4.3 Retail Energy Forecast and Load Responsibility | 14 |
| 4.4 Energy Forecast Uncertainty | 18 |
| 5 Peak Demand Forecast | 19 |
| 5.1 Econometric Modeling Process – Peak Demand | 19 |
| 5.2 Peak Demand Forecast Adjustments and Load Responsibility..... | 20 |
| 5.3 Peak Demand Forecast Uncertainty | 22 |
| 6 Retail Customer Forecast..... | 24 |
| Appendix A – Data Sources..... | 27 |
| Appendix B – Expected DSM Program Impacts | 30 |
| Appendix C – Distributed Generation (DG) Considerations | 33 |

Executive Summary

This report presents Oklahoma Gas & Electric Services' (OG&E) 2015 Load Forecasts. It describes both energy and peak demand forecasting models developed by OG&E with input from OG&E's Load Forecasting Team.

The 2015 retail sales forecast utilized the revenue class-based econometric modeling framework that has been in place for over a decade. The 2015 load responsibility peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility series. The hourly modeling approach has been used since the 2000 forecast.

The load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of OG&E electricity prices for price-sensitive customer classes. The load forecast contains the energy efficiency impact expected from the anticipated implementation of future national energy efficiency standards for appliances, lighting products and equipment. The final energy and demand forecast includes Federal Energy Regulatory Commission (FERC) jurisdictional wholesale contracts as post-modeling adjustments. (All OG&E wholesale contracts are scheduled to expire by mid-2015.) OG&E Demand Side Management (DSM) programs are now included in the final energy and demand forecasts as post-modeling adjustments.

The economic data, on which the forecast relies, indicates the economy in OG&E's service territory has experienced a vibrant recovery since the Great Recession. Regional economic indicators have outpaced those at the national level over the past few years. Oil prices dropped sharply in the second half of 2014 impacting the oil and gas industry, as well as manufacturing, and caused energy companies to make cuts in employment and compensation. Other sectors have benefited from lower oil prices and consumer spending, prices and wages have increased.

The energy and demand forecasts through 2025 are shown in tables on the next pages. The retail energy forecast is anticipated to grow at an average annual rate of 0.76%. The final energy sales forecast, after adjusting for OG&E DSM programs, projects an average annual growth at 0.26%. Retail peak demand is anticipated to grow at an average annual rate of 0.26% over the next decade. The final demand forecast after adjustments is nearly flat across the 10 year forecast horizon.

2015 Energy Forecast

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| FERC | | | | | | | | | | | |
| AVEC | 524,494 | - | - | - | - | - | - | - | - | - | - |
| MWH Sales | | | | | | | | | | | |
| Without Losses | | | | | | | | | | | |
| OMPA | - | - | - | - | - | - | - | - | - | - | - |
| MDEA | - | - | - | - | - | - | - | - | - | - | - |
| Total FERC Sales | 524,494 | - | - | - | - | - | - | - | - | - | - |
| | -100.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| Retail | | | | | | | | | | | |
| MWH Sales | | | | | | | | | | | |
| Without Losses | | | | | | | | | | | |
| or OG&E DSM | | | | | | | | | | | |
| Residential | 9,502,755 | 9,682,506 | 9,817,149 | 9,877,473 | 9,943,993 | 10,025,812 | 10,074,352 | 10,106,029 | 10,148,214 | 10,193,954 | 10,248,527 |
| Commercial | 7,299,132 | 7,450,095 | 7,563,237 | 7,664,728 | 7,761,310 | 7,859,623 | 7,959,390 | 8,060,348 | 8,165,186 | 8,272,241 | 8,383,794 |
| Industrial | 3,792,785 | 3,755,917 | 3,749,309 | 3,746,714 | 3,738,974 | 3,727,966 | 3,716,393 | 3,703,680 | 3,692,629 | 3,683,344 | 3,675,973 |
| Petroleum | 3,466,280 | 3,484,668 | 3,469,794 | 3,479,644 | 3,489,450 | 3,499,521 | 3,503,754 | 3,506,130 | 3,511,159 | 3,514,861 | 3,518,830 |
| Street Lighting | 64,643 | 62,366 | 59,498 | 56,626 | 53,742 | 50,780 | 47,763 | 44,706 | 41,606 | 38,458 | 35,261 |
| Public Authority | 3,223,394 | 3,266,719 | 3,344,998 | 3,429,600 | 3,508,597 | 3,594,046 | 3,677,091 | 3,754,429 | 3,832,302 | 3,914,425 | 3,998,589 |
| Total Retail Sales | 27,348,990 | 27,702,270 | 28,003,984 | 28,254,786 | 28,496,066 | 28,757,748 | 28,978,744 | 29,175,322 | 29,391,096 | 29,617,283 | 29,860,974 |
| | 1.29% | 1.09% | 0.90% | 0.85% | 0.92% | 0.77% | 0.77% | 0.68% | 0.74% | 0.77% | 0.82% |
| Total | | | | | | | | | | | |
| MWH Sales | | | | | | | | | | | |
| With Losses | | | | | | | | | | | |
| Total Retail Sales + FERC | 27,873,484 | 27,702,270 | 28,003,984 | 28,254,786 | 28,496,066 | 28,757,748 | 28,978,744 | 29,175,322 | 29,391,096 | 29,617,283 | 29,860,974 |
| Losses | 1,937,207 | 1,925,308 | 1,946,277 | 1,963,708 | 1,980,477 | 1,998,663 | 2,014,023 | 2,027,685 | 2,042,681 | 2,058,401 | 2,075,338 |
| Energy Subtotal | 29,810,691 | 29,627,578 | 29,950,261 | 30,218,494 | 30,476,542 | 30,756,411 | 30,992,767 | 31,203,007 | 31,433,777 | 31,675,684 | 31,936,311 |
| | -0.61% | 1.09% | 0.90% | 0.85% | 0.92% | 0.77% | 0.77% | 0.68% | 0.74% | 0.77% | 0.82% |
| OG&E DSM | | | | | | | | | | | |
| MWH Reduction | 361,637 | 461,047 | 563,439 | 671,890 | 773,318 | 869,487 | 969,793 | 1,065,390 | 1,152,721 | 1,244,446 | 1,331,833 |
| Load Responsibility | | | | | | | | | | | |
| MWH | | | | | | | | | | | |
| Load Responsibility = Total Sales with Losses and DSM Reduction | 29,449,054 | 29,166,530 | 29,386,822 | 29,546,604 | 29,703,225 | 29,886,924 | 30,022,974 | 30,137,617 | 30,281,057 | 30,431,239 | 30,604,479 |
| | -0.96% | 0.76% | 0.54% | 0.53% | 0.62% | 0.46% | 0.38% | 0.48% | 0.50% | 0.57% | 0.57% |

2015 Peak Demand Forecast

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|--|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| FERC Demand (MW) | | | | | | | | | | | |
| Without Losses | - | - | - | - | - | - | - | - | - | - | - |
| AVEC | - | - | - | - | - | - | - | - | - | - | - |
| SPA | - | - | - | - | - | - | - | - | - | - | - |
| OMPA | - | - | - | - | - | - | - | - | - | - | - |
| MDEA | - | - | - | - | - | - | - | - | - | - | - |
| Total FERC w/o Losses | - | - | - | - | - | - | - | - | - | - | - |
| Losses | - | - | - | - | - | - | - | - | - | - | - |
| Total FERC w/ Losses | - | - | - | - | - | - | - | - | - | - | - |
| | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| Total Retail Demand | 6,218 | 6,265 | 6,344 | 6,388 | 6,437 | 6,469 | 6,532 | 6,566 | 6,611 | 6,636 | 6,698 |
| | 0.76% | 0.76% | 1.25% | 0.69% | 0.77% | 0.49% | 0.97% | 0.52% | 0.68% | 0.38% | 0.94% |
| Pre OG&E DSM Load Responsibility (MW) | | | | | | | | | | | |
| Demand Subtotal = Total Retail Load + FERC, Losses Added | 6,218 | 6,265 | 6,344 | 6,388 | 6,437 | 6,469 | 6,532 | 6,566 | 6,611 | 6,636 | 6,698 |
| | 0.76% | 0.76% | 1.25% | 0.69% | 0.77% | 0.49% | 0.97% | 0.52% | 0.68% | 0.38% | 0.94% |
| Pre OG&E DSM Load Factor | 55% | 54% | 54% | 54% | 54% | 54% | 54% | 54% | 54% | 54% | 54% |
| OG&E DSM | 332 | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |
| Net Load Responsibility (MW) | | | | | | | | | | | |
| Load Responsibility = Total Load with Losses and DSM Reduction | 5,886 | 5,898 | 5,916 | 5,900 | 5,924 | 5,931 | 5,968 | 5,978 | 6,000 | 6,001 | 6,041 |
| | 0.20% | 0.20% | 0.32% | -0.27% | 0.41% | 0.12% | 0.62% | 0.17% | 0.37% | 0.01% | 0.67% |
| DSM Adjusted Load Factor | 57% | 56% | 57% | 57% | 57% | 58% | 57% | 58% | 58% | 58% | 58% |
| Total Net Energy MWh | 29,449,054 | 29,166,530 | 29,386,822 | 29,546,604 | 29,703,225 | 29,886,924 | 30,022,974 | 30,137,617 | 30,281,057 | 30,431,239 | 30,604,479 |
| Load Factor | 57% | 56% | 57% | 57% | 57% | 58% | 57% | 58% | 58% | 58% | 58% |

This page intentionally left blank.

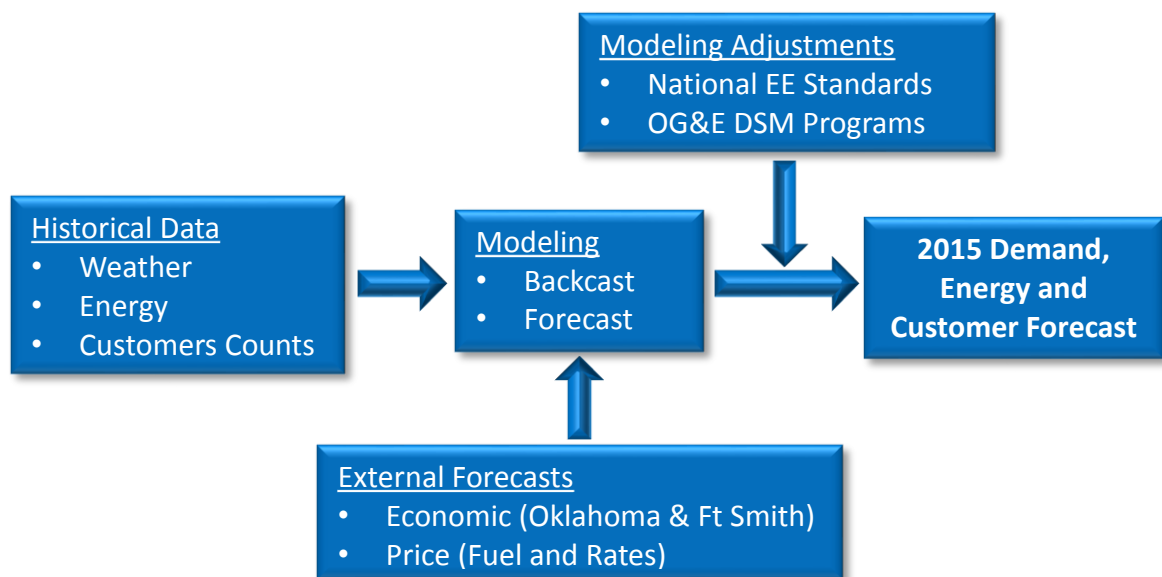
1 Introduction

The 2015 load forecast offers a ten year projection for energy, peak demand and customer growth. The 2015 retail sales (energy) forecast utilized the revenue class-based econometric modeling framework that has been in place for over a decade. The 2015 load responsibility peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility series. The econometric model used for customer growth relies heavily on population growth projections in OG&E's service territories.

The load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of OG&E electricity prices for price-sensitive customer classes. The final energy and demand forecast includes Federal Energy Regulatory Commission (FERC) jurisdictional wholesale contracts as post-modeling adjustments. (All OG&E wholesale contracts are scheduled to expire by mid-2015.) OG&E Demand Side Management Programs are now included in the final energy and demand forecasts as post-modeling adjustments.

A simplified process map, as shown in Figure 1, shows that historical data is integrated with external forecasts of the future. This modeling step first tests previous assumptions in a regression analysis to historical performance (this is also called the backcast). Assumptions are adjusted as needed to produce the future forecast for each revenue class. Modeling adjustments are made to the forecast to incorporate additional changes before the final forecast is produced.

Figure 1 – Load Forecast Process



2 Economic Outlook

KEY TAKEAWAYS:

- *Although Oklahoma economic activity has been mixed recently, the sharp decline in oil and gas prices has had a negative impact on activity and employment in the sector.*
- *Consumer spending has increased moderately and is expected to remain strong in the near term.*
- *Unemployment in Oklahoma is lower than the rest of the nation and is expected to remain fairly steady in the next few years.*

2.1 Economic Summary

Economic activity in Oklahoma is mixed across sectors and locations. Oil prices have fallen negatively affecting employment and compensation in the oil and gas industry as well as in manufacturers who support the industry. Other industries like transportation, wholesale trade and professional and high-tech contacts have reported increased activity. Consumer spending rose moderately and real estate activity continued to increase with positive expectations for coming months. “Prices rose slightly in most industries and wage growth was steady, with many firms indicating plans to increase wages over the next year.”¹

2.2 Underlying Economic Fundamentals

“Oil prices dropped sharply in the second half of 2014, causing energy companies to make significant cuts in their 2015 capital spending budgets and, in some cases, lay off workers. Through April 2015, Oklahoma oil and gas jobs already have declined more than 10 percent from their late-2014 peak.”² Companies who sell goods and services to support the oil and natural gas industry have likewise experienced the recent downturn and local economies are impacted by less income taxes and sales taxes. Other industries like transportation are benefiting from the lower oil prices and consumers are transferring this savings into spending.

2.2.1 Oklahoma Employment

The largest decline in energy jobs has been in non-metro areas and “Oklahoma employment outside the two major metro areas of Oklahoma City and Tulsa is down 1.4 percent since December, with sharp declines not only in the energy sector but also in manufacturing, transportation and several services sectors.” Manufacturing employment, transportation, business service jobs and energy jobs have pulled total Oklahoma employment down by 0.2 percent from December to April. Tax revenues have declined and total tax receipts are 6 percent less than year-ago levels. “Employment in the Oklahoma City metro area has grown similarly to the

¹ Board of Governors of the Federal Reserve System, Summary of Commentary on Current Economic Conditions by Federal Reserve Districts (Beige Book), <http://www.federalreserve.gov/monetarypolicy/beigebook/>, (June 3, 2015).

² Wilkerson, Chad, “The Oklahoma Economist: How Much is the Oil Downturn Hurting the Overall Oklahoma Economy?” Federal Reserve Bank of Kansas City, <https://www.kansascityfed.org/~media/files/publicat/oke/2015/oil-downturn-hurting-ok-economy.pdf?la=en> (2nd Quarter, 2015).

nation through April despite sharp job losses in oil and gas employment, as other industries continue to grow.”²

Real Personal Income has high growth rates for next few years and then tapers off. This mostly follows the forecast in the U.S. economy to full employment by 2018 and then slowing in the longer term as constrained by U.S./Oklahoma labor force growth. Personal income can grow faster in the near term as unemployment is reduced and there is a cyclical increase in labor force participation (i.e., discouraged workers returning to the labor force). By 2018, however, labor force growth will slow because of the aging of the population and unemployment will be as low as it will go, so total wages and salaries/personal income will grow more slowly (both nationwide and in Oklahoma).³

2.2.2 Oklahoma Energy Sector

The slowdown in the energy sector continues with the number of active oil drilling rigs declining and layoffs at oil and gas firms. Drilling locations have narrowed to the most productive areas or where drilling rights need to be retained and production has slowed slightly. If oil and natural gas prices rebound then drilling could ramp back within a year.¹ April and May prices reached \$60 per barrel which is close the threshold companies reported they needed to be profitable. These levels remain uncertain with international events and demands but the duration of the oil downturn is dependent on these oil prices.²

2.2.3 Consumer Spending

“Consumer spending activity rose moderately and remained higher than a year ago, with solid expectations heading forward.” Retail sales are considerably higher than year-ago including increases in building materials and home improvement products. Auto sales increased compared to last year while restaurant sales were below year ago levels. Retail selling, restaurant, and transportation prices rose while prices of raw materials and finished goods declined. Wages increased with most sectors expecting labor cost increases within the next year.¹

2.2.4 Manufacturing Sector

Manufacturing production in the OG&E service territory is closely related to oil and natural gas drilling activity. Manufacturing production fell sharply in Oklahoma along with manufacturing capital spending and export orders. Transportation activity increased over last year with “solid projects for future months.”¹

2.2.5 Real Estate and Construction

Residential real estate sales increased with low- and medium-priced homes outpacing sales of higher-priced homes. Sales and prices remain steady with inventories expected to decline. New housing starts and construction supply sales were flat but are expected to rise in future months. Commercial activity continues to increase and is expected to strengthen.¹

³ Rickman, Dan, 2015 Economic Indicator Forecast, June 18, 2015.

2.3 Role of Economic Data in 2015 Energy Sales Forecast

The 2015 retail energy forecast is based on retail sector-level econometric models representing OG&E's Oklahoma and Arkansas service territories. Historical and forecast economic variables (drivers) are provided by the Center for Applied Economic Research at Oklahoma State University (OSU). The historical economic data is compared to actual retail sales to determine a correlation. Then the economic forecast parameters are used to predict retail energy based on historically-defined correlations.

2.4 Economic Drivers for Energy Forecast

The overall 2015 Economic Forecast calls for healthy increases in economic growth in Oklahoma and Ft. Smith over the next five years. The economic drivers for Ft. Smith show higher growth rates over the next five years in comparison to the previous decade due to relatively poor economic conditions during the previous decade. The growth rates for 2021 to 2025 are expected to remain positive as the prolonged economic recovery continues nationally. Table 1 shows the historical and projected annual average growth rates of the primary economic drivers utilized in the retail energy forecast.

Table 1 - Economic Driver Growth Rates

| Economic Drivers and Models | | | Economic Driver Average Annual Growth Rates | | |
|-----------------------------|------------------|--|---|-----------|-----------|
| | | | 2004 - 2014 | 2015-2020 | 2021-2025 |
| Oklahoma | Residential | Real Personal Income Ex-Energy - OKC | 2.64% | 2.66% | 1.58% |
| | Commercial | OKC Real Gross Metro Product (Ex-Energy) | 2.57% | 2.54% | 1.36% |
| | Industrial | OKC Real Manufactured Gross Product | 2.68% | 5.53% | 3.95% |
| | Petroleum | Natural Resources & Mining Personal Income | 13.61% | 4.80% | 4.21% |
| | Street Lighting | OKC Population | 1.53% | 1.30% | 1.31% |
| | Public Authority | Real Personal Income-Ex Energy | 2.87% | 3.40% | 3.21% |
| Arkansas - Ft. Smith | Residential | Real Gross Metro Product | 0.97% | 2.09% | 1.91% |
| | Commercial | Nonfarm Proprietor Income | 1.21% | 3.70% | 3.41% |
| | Industrial | Manufacturing | -3.93% | -2.23% | -2.78% |
| | Petroleum | N/A | | | |
| | Street Lighting | Population | 0.62% | 0.38% | 0.50% |
| | Public Authority | Real Gross Metro Product | 0.97% | 2.09% | 1.91% |

3 OG&E Demand Side Management Summary

KEY TAKEAWAYS:

- *Demand Side Management programs reduce the load requirements on the system.*
- *Historical savings from previously implemented programs are already embedded in the load forecast.*

OG&E Demand Side Management programs reduce energy and demand on OG&E's system. Detailed descriptions of current programs can be found in Appendix B – Expected DSM Program Impacts.

The impact of programs implemented before 2012 is embedded in the baseline energy and peak demand forecasts. The expected impacts of current and future programs have been subtracted from the baseline forecast to calculate the final energy and peak demand forecasts. Table 2 and

Table 3 show the expected impacts of these programs.

Table 2 – Expected *Energy* Reduction from OG&E DSM Programs

| Energy (GWh) | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------------------|------|------|------|------|------|------|------|-------|-------|-------|-------|
| Current Portfolio | 318 | 318 | 318 | 318 | 317 | 316 | 313 | 307 | 300 | 293 | 285 |
| 2016 Portfolio: EE | - | 94 | 191 | 294 | 294 | 294 | 293 | 292 | 290 | 286 | 281 |
| 2019 Portfolio: EE | - | - | - | - | 101 | 198 | 301 | 301 | 301 | 300 | 299 |
| 2022 Portfolio: EE | - | - | - | - | - | - | - | 101 | 198 | 301 | 301 |
| 2025 Portfolio: EE | - | - | - | - | - | - | - | - | - | - | 101 |
| IVVC | 21 | 25 | 29 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| LRR | 3 | 3 | 4 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 |
| Smart Hours | 20 | 21 | 21 | 22 | 23 | 23 | 24 | 25 | 25 | 25 | 26 |
| Total Net Energy Reduction | 362 | 461 | 563 | 672 | 773 | 869 | 970 | 1,065 | 1,153 | 1,244 | 1,332 |

Table 3 – Expected *Peak Demand* Reduction from OG&E DSM Programs

| Demand (MW) | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------------------|------|------|------|------|------|------|------|------|------|------|------|
| Current Portfolio | 81 | 81 | 81 | 81 | 81 | 80 | 79 | 78 | 76 | 74 | 72 |
| 2016 Portfolio: EE | - | 20 | 42 | 66 | 66 | 66 | 66 | 65 | 65 | 64 | 63 |
| 2019 Portfolio: EE | - | - | - | - | 22 | 44 | 68 | 68 | 68 | 67 | 67 |
| 2022 Portfolio: EE | - | - | - | - | - | - | - | 22 | 44 | 68 | 68 |
| 2025 Portfolio: EE | - | - | - | - | - | - | - | - | - | - | 22 |
| IVVC | 41 | 54 | 67 | 82 | 82 | 82 | 82 | 82 | 82 | 82 | 82 |
| LRR | 60 | 62 | 88 | 109 | 112 | 116 | 119 | 123 | 126 | 130 | 133 |
| Smart Hours | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| Total Net Demand Reduction | 332 | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |

4 Energy Forecast

KEY TAKEAWAYS:

- *Total retail energy increases by an average of 0.88% per year*
- *Total retail energy for 2025 is expected to be 29,860,974 MWh*

4.1 Econometric Modeling Process - Energy

The retail energy forecast is generated from a regression analysis of historical energy, economic growth patterns and annual weather. OG&E's retail energy is divided into six market segments (Residential, Commercial, Industrial, Oil Field, Street Lighting and Public Authority) for both states (Oklahoma and Arkansas). Within each segment, a variety of different models is prepared and tested against actual historical sales to determine which model provides the highest quality forecast for that market segment. The models test a range of variable combinations (i.e. model specifications), each with separate intercept and slope coefficients.

The dependent variable is OG&E's retail energy sales by market segment. Key independent variables include:

- Electricity price paid by the customer.
- Economic conditions as reflected through various economic indicators.
- Cooling degree days, base 65. This cooling degree day variable effectively represents temperature impacts when daily average temperatures (average of the daily minimum and daily maximum temperatures) exceed 65 degrees.
- Heating degree days, base 65. This heating degree day variable effectively represents temperature impacts when daily average temperatures fall below 65 degrees.
- Monthly or seasonal variables, used to capture the highly seasonal nature of energy sales.

The monthly energy consumption analysis for each market segment follows a three-step process:

- Step 1.** Set up models for each market segment with different variable groups and generate estimates using the 2014 model specifications as a starting point
- Step 2.** Inspect goodness-of-fit and other important statistics (e.g., R-squared, t-statistics, multicollinearity statistics); compare actual versus predicted values of the dependent variable over the historical period.
- Step 3.** Adjust variables repeat steps 1 and 2 as needed until a final model specification is generated.

Between 10 and 50 models were estimated for each segment. The final model was not always the one with the "best fit." The overriding selection criterion was the model providing the best forecast. For example, if a model with an R-square of 0.95 had a larger error in the out-of-sample

period than an alternative model with an R-square of 0.93, the latter model was selected. Table 4 and Table 5 detail the final model variables used for Oklahoma and Arkansas, respectively.

Table 4 – Oklahoma Energy Model Drivers

| | Primary Economic Drivers | Other Drivers |
|------------------|--|---|
| | Oklahoma Economic Outlook | |
| Residential | Real Personal Income Ex-Energy - OKC | Real Residential electric price, Heating-Degree Days (HDD), Cooling-Degree Days (CDD) |
| Commercial | OKC Real Gross Metro Product (Ex-Energy) | OKC Population, Real Commercial electric price, HDD, CDD |
| Industrial | OKC Real Mfg. Gross Product | CPI, OKC Labor Force |
| Oil Field | Nominal Gas Price | Petroleum Electric Price |
| Street lighting | OKC Population | Free Street Lighting Service Timing Variable |
| Public Authority | Real Personal Income-Ex Energy | Real Public Authority electric price, HDD, CDD, OK Population |

* Some models also have monthly-specific intercept and interaction terms.

Table 5 – Arkansas Energy Model Drivers

| | Primary Economic Drivers | Other Drivers |
|------------------|---|---|
| | Arkansas Economic Outlook – Ft. Smith | |
| Residential | Real Gross Metro Product | Ft. Smith Population, Real Residential electric price, HDD, CDD |
| Commercial | Non-Farm Proprietor Income | Ft. Smith Population, Real Commercial electric price, HDD, CDD |
| Industrial | Fort Smith Real Manufacturing Gross Product | Ft. Smith Population |
| Oil Field | Nominal Gas Price | Petroleum Electric Price |
| Street lighting | Population | N/A |
| Public Authority | Real Gross Metro Product | Real Public Authority electric price, HDD, CDD |

* Some models also have monthly-specific intercept and interaction terms.

4.2 2015 Energy Forecast Adjustments

The regression analysis cannot predict external changes that will occur in the future. Therefore, adjustments must be made to the model before the final forecast is generated.

4.2.1 National Energy Efficiency Adjustment

The residential, commercial and industrial sectors for Oklahoma and Arkansas were adjusted for energy efficiency that is expected as a result of the anticipated implementation of national energy efficiency standards for appliances, lighting products and equipment. The adjustments were

made by utilizing state-level energy efficiency impact data from the “Appliance Standards Awareness Project”¹ and applying a ratio based on the relationship of OG&E’s service territory to the state. Existing codes and standards are assumed to be included in the baseline forecast. The energy efficiency adjustments include standards expected to be implemented in the future. We are nearing the middle of the implementation cycle of the new appliance standards and as consumer’s update/upgrade their equipment, the effects on their energy consumption is partially reflected in our historical data so the adjustments were discounted by 50% to avoid double counting. The results of these calculations are shown in Table 6.

Table 6 – Energy Efficiency Adjustments

| Oklahoma Residential Energy Efficiency | | | | Arkansas Residential Energy Efficiency | | | |
|--|-----------------------------------|--|--------------------------------------|--|-----------------------------------|--|--------------------------------------|
| Year | Oklahoma Residential Baseline MWh | Oklahoma Res. Energy Efficiency MWh Adjustment | Final Oklahoma Residential Model MWh | Year | Arkansas Residential Baseline MWh | Arkansas Res. Energy Efficiency MWh Adjustment | Final Arkansas Residential Model MWh |
| 2015 | 8,765,521 | 3,473 | 8,762,048 | 2015 | 741,011 | 304 | 740,707 |
| 2016 | 8,946,682 | 8,245 | 8,938,437 | 2016 | 744,791 | 722 | 744,069 |
| 2017 | 9,083,290 | 15,839 | 9,067,451 | 2017 | 751,087 | 1,389 | 749,698 |
| 2018 | 9,153,451 | 30,848 | 9,122,603 | 2018 | 757,555 | 2,684 | 754,871 |
| 2019 | 9,235,475 | 50,821 | 9,184,654 | 2019 | 763,756 | 4,417 | 759,339 |
| 2020 | 9,339,199 | 76,578 | 9,262,621 | 2020 | 769,848 | 6,657 | 763,191 |
| 2021 | 9,427,411 | 118,588 | 9,308,823 | 2021 | 775,852 | 10,323 | 765,529 |
| 2022 | 9,498,632 | 160,598 | 9,338,034 | 2022 | 781,984 | 13,989 | 767,995 |
| 2023 | 9,580,068 | 202,608 | 9,377,460 | 2023 | 788,409 | 17,655 | 770,754 |
| 2024 | 9,664,861 | 244,618 | 9,420,242 | 2024 | 795,033 | 21,321 | 773,712 |
| 2025 | 9,758,675 | 286,628 | 9,472,046 | 2025 | 801,468 | 24,987 | 776,481 |

¹Potential Oklahoma state-level benefits: http://www.appliance-standards.org/sites/default/files/fedappl_ok.pdf
 Potential Arkansas state-level benefits: http://www.appliance-standards.org/sites/default/files/fedappl_ar.pdf

Table 6 – Energy Efficiency Adjustments (cont.)

| Oklahoma Commercial Energy Efficiency | | | | Arkansas Commercial Energy Efficiency | | | |
|--|----------------------------------|--|-------------------------------------|--|----------------------------------|--|-------------------------------------|
| Year | Oklahoma Commercial Baseline MWh | Oklahoma Com. Energy Efficiency MWh Adjustment | Final Oklahoma Commercial Model MWh | Year | Arkansas Commercial Baseline MWh | Arkansas Com. Energy Efficiency MWh Adjustment | Final Arkansas Commercial Model MWh |
| 2015 | 6,550,900 | 0 | 6,550,900 | 2015 | 748,233 | 0 | 748,233 |
| 2016 | 6,697,572 | 731 | 6,696,841 | 2016 | 753,324 | 70 | 753,254 |
| 2017 | 6,816,722 | 11,784 | 6,804,937 | 2017 | 759,434 | 1,134 | 758,300 |
| 2018 | 6,931,548 | 32,756 | 6,898,793 | 2018 | 769,208 | 3,273 | 765,935 |
| 2019 | 7,042,919 | 53,794 | 6,989,125 | 2019 | 777,602 | 5,417 | 772,185 |
| 2020 | 7,158,343 | 78,694 | 7,079,649 | 2020 | 788,015 | 8,041 | 779,974 |
| 2021 | 7,277,343 | 104,749 | 7,172,594 | 2021 | 797,646 | 10,850 | 786,796 |
| 2022 | 7,397,489 | 130,804 | 7,266,685 | 2022 | 807,322 | 13,659 | 793,663 |
| 2023 | 7,521,039 | 156,859 | 7,364,180 | 2023 | 817,474 | 16,468 | 801,006 |
| 2024 | 7,646,292 | 182,914 | 7,463,378 | 2024 | 828,141 | 19,277 | 808,864 |
| 2025 | 7,775,731 | 208,969 | 7,566,762 | 2025 | 839,119 | 22,086 | 817,033 |

| Oklahoma Industrial Energy Efficiency | | | | Arkansas Industrial Energy Efficiency | | | |
|--|----------------------------------|--|-------------------------------------|--|----------------------------------|--|-------------------------------------|
| Year | Oklahoma Industrial Baseline MWh | Oklahoma Ind. Energy Efficiency MWh Adjustment | Final Oklahoma Industrial Model MWh | Year | Arkansas Industrial Baseline MWh | Arkansas Ind. Energy Efficiency MWh Adjustment | Final Arkansas Industrial Model MWh |
| 2015 | 2,752,066 | 0 | 2,752,066 | 2015 | 1,040,719 | 0 | 1,040,719 |
| 2016 | 2,717,566 | 0 | 2,717,566 | 2016 | 1,038,351 | 0 | 1,038,351 |
| 2017 | 2,713,141 | 7,987 | 2,705,154 | 2017 | 1,045,449 | 1,294 | 1,044,155 |
| 2018 | 2,706,831 | 15,973 | 2,690,858 | 2018 | 1,058,445 | 2,588 | 1,055,856 |
| 2019 | 2,696,970 | 23,960 | 2,673,010 | 2019 | 1,069,847 | 3,883 | 1,065,964 |
| 2020 | 2,688,131 | 31,947 | 2,656,185 | 2020 | 1,076,957 | 5,177 | 1,071,781 |
| 2021 | 2,679,943 | 40,829 | 2,639,114 | 2021 | 1,083,914 | 6,634 | 1,077,280 |
| 2022 | 2,669,847 | 49,712 | 2,620,135 | 2022 | 1,091,635 | 8,090 | 1,083,545 |
| 2023 | 2,659,704 | 58,595 | 2,601,109 | 2023 | 1,101,068 | 9,547 | 1,091,520 |
| 2024 | 2,650,307 | 67,478 | 2,582,828 | 2024 | 1,111,520 | 11,004 | 1,100,515 |
| 2025 | 2,642,762 | 76,361 | 2,566,401 | 2025 | 1,122,033 | 12,461 | 1,109,572 |

4.2.2 Streetlight LED Implementation Adjustment

Over the next 10 years, OG&E plans to replace current streetlights with LED's through attrition. Adjustments were made to the Streetlight forecast to phase in the LED implementation over the

forecast horizon so that by the 10th year the forecast will be reduced by half to account for the efficiencies in the LED's. The results of these adjustments are shown in Table 7.

Table 7 – Streetlight LED Implementation Adjustments

| Oklahoma Streetlight Energy Efficiency | | | | Arkansas Streetlight Energy Efficiency | | | |
|--|--------------------------------------|---|---|--|--------------------------------------|---|---|
| Year | Final Oklahoma Streetlight Model MWh | Oklahoma Street Light LED Implementation MWh Adjustment | Final Oklahoma Streetlight with LED MWh | Year | Final Arkansas Streetlight Model MWh | Arkansas Street Light LED Implementation MWh Adjustment | Final Arkansas Streetlight with LED MWh |
| 2015 | 55,612 | 0 | 55,612 | 2015 | 9,031 | 0 | 9,031 |
| 2016 | 56,640 | 2,832 | 53,808 | 2016 | 9,009 | 450 | 8,558 |
| 2017 | 57,102 | 5,710 | 51,392 | 2017 | 9,007 | 901 | 8,106 |
| 2018 | 57,590 | 8,639 | 48,952 | 2018 | 9,029 | 1,354 | 7,675 |
| 2019 | 58,110 | 11,622 | 46,488 | 2019 | 9,067 | 1,813 | 7,254 |
| 2020 | 58,604 | 14,651 | 43,953 | 2020 | 9,103 | 2,276 | 6,827 |
| 2021 | 59,104 | 17,731 | 41,373 | 2021 | 9,129 | 2,739 | 6,390 |
| 2022 | 59,623 | 20,868 | 38,755 | 2022 | 9,155 | 3,204 | 5,951 |
| 2023 | 60,159 | 24,064 | 36,096 | 2023 | 9,184 | 3,674 | 5,510 |
| 2024 | 60,708 | 27,318 | 33,389 | 2024 | 9,216 | 4,147 | 5,069 |
| 2025 | 61,272 | 30,636 | 30,636 | 2025 | 9,249 | 4,625 | 4,625 |

4.2.3 FERC Wholesale Load Adjustments

OG&E utilized historical wholesale sales data and the expiration dates for current contracts to produce the forecasts of FERC wholesale sales. Using an econometric forecasting approach similar to what was used for the retail energy forecast models; OG&E produced separate forecasts of wholesale sales for the active wholesale contracts. Out of model adjustments were then made to those forecasts to reflect current expiration dates.

4.3 Retail Energy Forecast and Load Responsibility

Table 8 summarizes the 2015 retail energy forecast (excluding line losses) by state and for the company as a whole before OG&E DSM program reductions. Weather-normalized annual retail sales are expected to grow from 27,349 GWh in 2015 to 29,861 GWh in 2025, which translates into a 9.2% increase over OG&E's planning horizon, or an average annual increase of 0.88%.

Table 8 – 2015 Retail Energy Forecast (MWh)

| | Year | Residential | Commercial | Industrial | Oil Field | Street Lighting | Public Authority | Total |
|-------------------------|------------|-------------|------------|------------|-----------|-----------------|------------------|------------|
| Oklahoma MWH Forecast | 2015 | 8,762,048 | 6,550,900 | 2,752,066 | 3,455,153 | 55,612 | 3,082,316 | 24,658,096 |
| | 2016 | 8,938,437 | 6,696,841 | 2,717,566 | 3,473,549 | 53,808 | 3,123,482 | 25,003,683 |
| | 2017 | 9,067,451 | 6,804,937 | 2,705,154 | 3,458,677 | 51,392 | 3,199,043 | 25,286,654 |
| | 2018 | 9,122,603 | 6,898,793 | 2,690,858 | 3,468,528 | 48,952 | 3,281,627 | 25,511,360 |
| | 2019 | 9,184,654 | 6,989,125 | 2,673,010 | 3,478,335 | 46,488 | 3,358,656 | 25,730,267 |
| | 2020 | 9,262,621 | 7,079,649 | 2,656,185 | 3,488,407 | 43,953 | 3,441,806 | 25,972,620 |
| | 2021 | 9,308,823 | 7,172,594 | 2,639,114 | 3,492,641 | 41,373 | 3,522,615 | 26,177,159 |
| | 2022 | 9,338,034 | 7,266,685 | 2,620,135 | 3,495,018 | 38,755 | 3,597,768 | 26,356,395 |
| | 2023 | 9,377,460 | 7,364,180 | 2,601,109 | 3,500,048 | 36,096 | 3,673,472 | 26,552,364 |
| | 2024 | 9,420,242 | 7,463,378 | 2,582,828 | 3,503,751 | 33,389 | 3,753,413 | 26,757,001 |
| 2025 | 9,472,046 | 7,566,762 | 2,566,401 | 3,507,720 | 30,636 | 3,835,484 | 26,979,049 | |
| Arkansas MWH Forecast | 2015 | 740,707 | 748,233 | 1,040,719 | 11,127 | 9,031 | 141,078 | 2,690,894 |
| | 2016 | 744,069 | 753,254 | 1,038,351 | 11,118 | 8,558 | 143,237 | 2,698,587 |
| | 2017 | 749,698 | 758,300 | 1,044,155 | 11,116 | 8,106 | 145,955 | 2,717,330 |
| | 2018 | 754,871 | 765,935 | 1,055,856 | 11,115 | 7,675 | 147,974 | 2,743,426 |
| | 2019 | 759,339 | 772,185 | 1,065,964 | 11,115 | 7,254 | 149,942 | 2,765,798 |
| | 2020 | 763,191 | 779,974 | 1,071,781 | 11,114 | 6,827 | 152,240 | 2,785,128 |
| | 2021 | 765,529 | 786,796 | 1,077,280 | 11,113 | 6,390 | 154,477 | 2,801,585 |
| | 2022 | 767,995 | 793,663 | 1,083,545 | 11,112 | 5,951 | 156,661 | 2,818,927 |
| | 2023 | 770,754 | 801,006 | 1,091,520 | 11,111 | 5,510 | 158,831 | 2,838,732 |
| | 2024 | 773,712 | 808,864 | 1,100,515 | 11,110 | 5,069 | 161,012 | 2,860,281 |
| 2025 | 776,481 | 817,033 | 1,109,572 | 11,109 | 4,625 | 163,104 | 2,881,924 | |
| Total OG&E MWH Forecast | 2015 | 9,502,755 | 7,299,132 | 3,792,785 | 3,466,280 | 64,643 | 3,223,394 | 27,348,990 |
| | 2016 | 9,682,506 | 7,450,095 | 3,755,917 | 3,484,668 | 62,366 | 3,266,719 | 27,702,270 |
| | 2017 | 9,817,149 | 7,563,237 | 3,749,309 | 3,469,794 | 59,498 | 3,344,998 | 28,003,984 |
| | 2018 | 9,877,473 | 7,664,728 | 3,746,714 | 3,479,644 | 56,626 | 3,429,600 | 28,254,786 |
| | 2019 | 9,943,993 | 7,761,310 | 3,738,974 | 3,489,450 | 53,742 | 3,508,597 | 28,496,066 |
| | 2020 | 10,025,812 | 7,859,623 | 3,727,966 | 3,499,521 | 50,780 | 3,594,046 | 28,757,748 |
| | 2021 | 10,074,352 | 7,959,390 | 3,716,393 | 3,503,754 | 47,763 | 3,677,091 | 28,978,744 |
| | 2022 | 10,106,029 | 8,060,348 | 3,703,680 | 3,506,130 | 44,706 | 3,754,429 | 29,175,322 |
| | 2023 | 10,148,214 | 8,165,186 | 3,692,629 | 3,511,159 | 41,606 | 3,832,302 | 29,391,096 |
| | 2024 | 10,193,954 | 8,272,241 | 3,683,344 | 3,514,861 | 38,458 | 3,914,425 | 29,617,283 |
| 2025 | 10,248,527 | 8,383,794 | 3,675,973 | 3,518,830 | 35,261 | 3,998,589 | 29,860,974 | |

Projected growth rates associated with these data are comparable to those observed over the last decade. Weather-normalized sales grew by approximately 1.33% annually from 2004 through 2014. Average annual growth is projected to be similar from 2015 to 2020 (1.01%), Average

annual sales growth in the last half of the forecast, the 2021–2025 period, will be lower (0.76%). This is consistent with economic growth rates noted in the **Economic Outlook** section of this report. The retail energy growth rates by state and sector are shown in Table 9.

Table 9 – Retail Energy Growth Rates

| | Year | Residential | Commercial | Industrial | Oil Field | Street Lighting | Public Authority | Total |
|-------------------------|------|-------------|------------|------------|-----------|-----------------|------------------|-------|
| Oklahoma MWH Forecast | 2016 | 2.01% | 2.23% | -1.25% | 0.53% | -3.25% | 1.34% | 1.40% |
| | 2017 | 1.44% | 1.61% | -0.46% | -0.43% | -4.49% | 2.42% | 1.13% |
| | 2018 | 0.61% | 1.38% | -0.53% | 0.28% | -4.75% | 2.58% | 0.89% |
| | 2019 | 0.68% | 1.31% | -0.66% | 0.28% | -5.03% | 2.35% | 0.86% |
| | 2020 | 0.85% | 1.30% | -0.63% | 0.29% | -5.45% | 2.48% | 0.94% |
| | 2021 | 0.50% | 1.31% | -0.64% | 0.12% | -5.87% | 2.35% | 0.79% |
| | 2022 | 0.31% | 1.31% | -0.72% | 0.07% | -6.33% | 2.13% | 0.68% |
| | 2023 | 0.42% | 1.34% | -0.73% | 0.14% | -6.86% | 2.10% | 0.74% |
| | 2024 | 0.46% | 1.35% | -0.70% | 0.11% | -7.50% | 2.18% | 0.77% |
| | 2025 | 0.55% | 1.39% | -0.64% | 0.11% | -8.25% | 2.19% | 0.83% |
| Arkansas MWH Forecast | 2016 | 0.45% | 0.67% | -0.23% | -0.07% | -5.23% | 1.53% | 0.29% |
| | 2017 | 0.76% | 0.67% | 0.56% | -0.02% | -5.28% | 1.90% | 0.69% |
| | 2018 | 0.69% | 1.01% | 1.12% | -0.01% | -5.32% | 1.38% | 0.96% |
| | 2019 | 0.59% | 0.82% | 0.96% | -0.01% | -5.48% | 1.33% | 0.82% |
| | 2020 | 0.51% | 1.01% | 0.55% | 0.00% | -5.89% | 1.53% | 0.70% |
| | 2021 | 0.31% | 0.87% | 0.51% | -0.01% | -6.39% | 1.47% | 0.59% |
| | 2022 | 0.32% | 0.87% | 0.58% | -0.01% | -6.88% | 1.41% | 0.62% |
| | 2023 | 0.36% | 0.93% | 0.74% | -0.01% | -7.40% | 1.38% | 0.70% |
| | 2024 | 0.38% | 0.98% | 0.82% | -0.01% | -8.02% | 1.37% | 0.76% |
| | 2025 | 0.36% | 1.01% | 0.82% | -0.01% | -8.76% | 1.30% | 0.76% |
| Total OG&E MWH Forecast | 2016 | 1.89% | 2.07% | -0.97% | 0.53% | -3.52% | 1.34% | 1.29% |
| | 2017 | 1.39% | 1.52% | -0.18% | -0.43% | -4.60% | 2.40% | 1.09% |
| | 2018 | 0.61% | 1.34% | -0.07% | 0.28% | -4.83% | 2.53% | 0.90% |
| | 2019 | 0.67% | 1.26% | -0.21% | 0.28% | -5.09% | 2.30% | 0.85% |
| | 2020 | 0.82% | 1.27% | -0.29% | 0.29% | -5.51% | 2.44% | 0.92% |
| | 2021 | 0.48% | 1.27% | -0.31% | 0.12% | -5.94% | 2.31% | 0.77% |
| | 2022 | 0.31% | 1.27% | -0.34% | 0.07% | -6.40% | 2.10% | 0.68% |
| | 2023 | 0.42% | 1.30% | -0.30% | 0.14% | -6.93% | 2.07% | 0.74% |
| | 2024 | 0.45% | 1.31% | -0.25% | 0.11% | -7.57% | 2.14% | 0.77% |
| | 2025 | 0.54% | 1.35% | -0.20% | 0.11% | -8.31% | 2.15% | 0.82% |

Table 10 combines the forecasts of wholesale sales with the retail energy forecast from Table 8 and expected OG&E DSM energy reductions from Table 2, yielding the 2015 energy forecast.

Table 10 – 2015 Energy Forecast including Wholesale, Losses and Planned OG&E DSM Programs

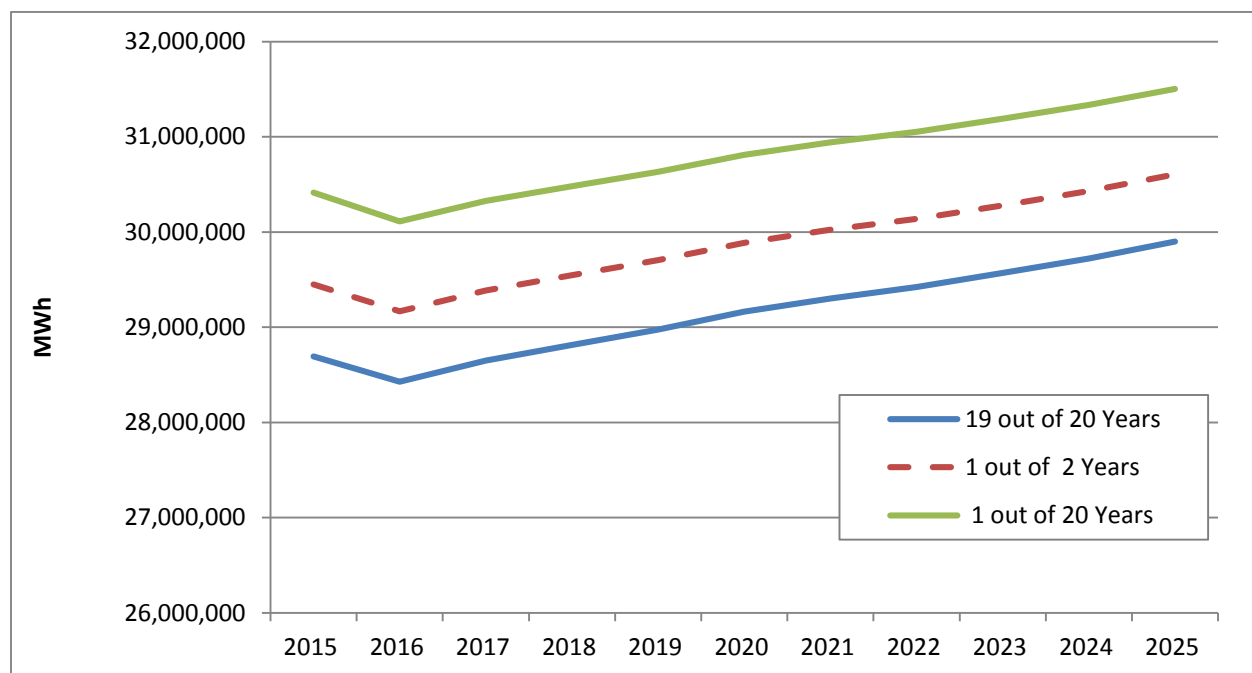
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|--|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| FERC | | | | | | | | | | | |
| MWH Sales | 524,494 | - | - | - | - | - | - | - | - | - | - |
| Without Losses | | | | | | | | | | | |
| OMPA | - | - | - | - | - | - | - | - | - | - | - |
| MDEA | - | - | - | - | - | - | - | - | - | - | - |
| Total FERC Sales | 524,494 | - | - | - | - | - | - | - | - | - | - |
| | | -100.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| Retail | | | | | | | | | | | |
| MWH Sales | 9,502,755 | 9,682,506 | 9,817,149 | 9,877,473 | 9,943,993 | 10,025,812 | 10,074,352 | 10,106,029 | 10,148,214 | 10,193,954 | 10,248,527 |
| Without Losses | 7,299,132 | 7,450,095 | 7,563,237 | 7,664,728 | 7,761,310 | 7,859,623 | 7,959,390 | 8,060,348 | 8,165,186 | 8,272,241 | 8,383,794 |
| or OG&E DSM | 3,792,785 | 3,755,917 | 3,749,309 | 3,746,714 | 3,738,974 | 3,727,966 | 3,716,393 | 3,703,680 | 3,692,629 | 3,683,344 | 3,675,973 |
| | 3,466,280 | 3,484,668 | 3,469,794 | 3,479,644 | 3,489,450 | 3,499,521 | 3,503,754 | 3,506,130 | 3,511,159 | 3,514,861 | 3,518,830 |
| | 64,643 | 62,366 | 59,498 | 56,626 | 53,742 | 50,780 | 47,763 | 44,706 | 41,606 | 38,458 | 35,261 |
| | 3,223,394 | 3,266,719 | 3,344,998 | 3,429,600 | 3,508,597 | 3,594,046 | 3,677,091 | 3,754,429 | 3,832,302 | 3,914,425 | 3,998,589 |
| Total Retail Sales | 27,348,990 | 27,702,270 | 28,003,984 | 28,254,786 | 28,496,066 | 28,757,748 | 28,978,744 | 29,175,322 | 29,391,096 | 29,617,283 | 29,860,974 |
| | | 1.29% | 1.09% | 0.90% | 0.85% | 0.92% | 0.77% | 0.68% | 0.74% | 0.77% | 0.82% |
| Total | | | | | | | | | | | |
| MWH Sales | 27,873,484 | 27,702,270 | 28,003,984 | 28,254,786 | 28,496,066 | 28,757,748 | 28,978,744 | 29,175,322 | 29,391,096 | 29,617,283 | 29,860,974 |
| With Losses | 1,937,207 | 1,925,308 | 1,946,277 | 1,963,708 | 1,980,477 | 1,998,663 | 2,014,023 | 2,027,685 | 2,042,681 | 2,058,401 | 2,075,338 |
| | 29,810,691 | 29,627,578 | 29,950,261 | 30,218,494 | 30,476,542 | 30,756,411 | 30,992,767 | 31,203,007 | 31,433,777 | 31,675,684 | 31,936,311 |
| | | -0.61% | 1.09% | 0.90% | 0.85% | 0.92% | 0.77% | 0.68% | 0.74% | 0.77% | 0.82% |
| OG&E DSM | | | | | | | | | | | |
| | 361,637 | 461,047 | 563,439 | 671,890 | 773,318 | 869,487 | 969,793 | 1,065,390 | 1,152,721 | 1,244,446 | 1,331,833 |
| Load Responsibility = Total Sales with Losses and DSM Reduction | 29,449,054 | 29,166,530 | 29,386,822 | 29,546,604 | 29,703,225 | 29,886,924 | 30,022,974 | 30,137,617 | 30,281,057 | 30,431,239 | 30,604,479 |
| | | -0.96% | 0.76% | 0.54% | 0.53% | 0.62% | 0.46% | 0.38% | 0.48% | 0.50% | 0.57% |

4.4 Energy Forecast Uncertainty

Weather uncertainty in the energy models is represented through a Monte Carlo modeling approach where the last three decades of weather are systematically entered into the various energy models to produce a distribution of possible sales outcomes.

The weather-year Monte Carlo approach essentially runs all weather years from 1981 to 2014 through the weather-sensitive energy models to develop a probability distribution of possible outcomes. Figure 2 shows the results directly from this modeling process for energy sales and includes FERC adjustments.

Figure 2 – Energy Model Forecast Outcomes by Weather Probability



The *1 out of 2 years* average weather line indicates there is a 50% probability that energy sales will reach this level or higher.

Now, consider the *1 out of 20 years* forecast. This line shows energy sales under more extreme weather events occurring just 5% of the time. Finally, the lower bound forecast (*19 out of 20 year* case) shows sales may fall below the normal weather forecast by approximately 725,000 MWh if weather is significantly milder than normal given expected economic performance.

5 Peak Demand Forecast

KEY TAKEAWAYS:

- *Retail peak demand increases by an average of 0.75% per year*
- *The expected peak demand in 2025 after OG&E DSM programs is 6,041MW*

5.1 Econometric Modeling Process – Peak Demand

The econometric modeling framework has been in place at OG&E since 2000. The modeling structure consists of 24 separate hourly equations, one for each hour of the day, with separate intercept and slope coefficients in the various models. The hourly equations are estimated over the May through September period.

The dependent variable is OG&E’s historical normalized load responsibility, less the fixed 25 MW Oklahoma Municipal Power Authority (OMPA) Power Sales Agreement (PSA) load¹, and includes line losses. Key independent variables include:

- Cooling degree hours, base 72. This cooling degree hour variable is calculated in a manner similar to cooling degree days and effectively represents temperature impacts when temperatures exceed 72 degrees.
- A second temperature variable, defined as temperature—98°, which addresses the “topping off” effect in which there is a reduction in the *rate* of load increases at very high temperatures.
- National Oceanic and Atmospheric Administration’s (NOAA) misery index reflecting the combined effects of humidity and warm temperatures. The misery build-up or duration of the misery index is captured through the weighted average of past hourly values of the misery index.²
- Wind speed.
- Economic growth as reflected through weather-adjusted retail energy sales, which represents the aggregate impact of economic conditions on the OG&E system. The sales are also normalized by the number of days in each month.

¹ OMPA PSA contract terminated 12/31/2013. It is considered in the historical data, but not in the forward-looking forecast.

² The lag structure is designed to pick up the effects of a heat wave lasting a few days or more. More electricity is demanded later (vs. earlier) in a heat wave, even when temperatures decline slightly. The implication is that “design temperature” is not sufficient for peak forecasting purposes. The temperature of the building is the result of the accumulated outdoor temperatures, less the impact of the HVAC system. The weighted average is capable of capturing the effects of both duration and nighttime cooling since high daytime temperatures and lower nighttime temperatures are reflected in the average.

Relevant weather stations are shown below in Table 11, along with the OG&E population estimates from the 2010 census used to weigh data from each station:

Table 11 – Weather Station Weights

| Weather Station | Population in OG&E Territory | Weight (% of OG&E population) |
|-----------------------------|------------------------------|-------------------------------|
| Oklahoma City (Will Rogers) | 1,322,249 | 63.8% |
| Fort Smith | 298,592 | 14.4% |
| Guthrie | 159,111 | 7.7% |
| Stillwater | 179,197 | 8.6% |
| Muskogee | 112,690 | 5.4% |

The peak demand forecast is generated via a probabilistic approach by using the last 33 available years of actual weather data. This Monte Carlo modeling approach runs all weather years from 1981 to 2013 through the peak demand model, while alternating the weather year “starting day” seven times for each day of the week. Since loads are much lower on weekends, alternating the starting day allows the model to determine the demand impact of actual weather events as if they had occurred on any day of the week.

This results in a matrix of 33 weather years by seven days, or a total of 231 simulations given the historical hourly weather data available to OG&E. The peak demand forecast is constructed by calculating a range of weather-feasible load forecasts for each year over the forecast horizon from the regression model results. As described above, this step generates 231 weather-feasible forecasts. These 231 annual load forecasts were ranked from highest to lowest and assigned probabilities to the occurrence of each forecast under the assumption of a uniform distribution (i.e., each weather has an equal chance of occurrence).

All of the highest values (peaks) in the resulting forecast distribution occur between 3:00 p.m. and 7:00 p.m. (Central Daylight Time), with the majority occurring at 5:00 p.m.

5.2 Peak Demand Forecast Adjustments and Load Responsibility

FERC wholesale load adjustments are made based on known and verifiable contract termination dates. Expiring contracts are subtracted from the normalized load responsibility forecast from the model to obtain final Load Responsibility forecasts. Table 12 reflects the 2015 Load Responsibility forecast after planned OG&E DSM Programs.

Table 12 – 2015 Peak Demand Forecast including Wholesale, Losses and Planned OG&E DSM Programs

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|--|-----------------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|------------|
| FERC Demand (MW) Without Losses | AVEC | - | - | - | - | - | - | - | - | - | - |
| | SPA | - | - | - | - | - | - | - | - | - | - |
| | OMPA | - | - | - | - | - | - | - | - | - | - |
| | MDEA | - | - | - | - | - | - | - | - | - | - |
| | Total FERC w/o Losses | - | - | - | - | - | - | - | - | - | - |
| | Losses | - | - | - | - | - | - | - | - | - | - |
| | Total FERC w/ Losses | - | - | - | - | - | - | - | - | - | - |
| | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| | 6,218 | 6,265 | 6,344 | 6,388 | 6,437 | 6,469 | 6,532 | 6,566 | 6,611 | 6,636 | 6,698 |
| | | 0.76% | 1.25% | 0.69% | 0.77% | 0.49% | 0.97% | 0.52% | 0.68% | 0.38% | 0.94% |
| Pre OG&E DSM Load Responsibility (MW) | 6,218 | 6,265 | 6,344 | 6,388 | 6,437 | 6,469 | 6,532 | 6,566 | 6,611 | 6,636 | 6,698 |
| | | 0.76% | 1.25% | 0.69% | 0.77% | 0.49% | 0.97% | 0.52% | 0.68% | 0.38% | 0.94% |
| Pre OG&E DSM Load Factor | 29,810,691 | 29,627,578 | 29,950,261 | 30,218,494 | 30,476,542 | 30,756,411 | 30,992,767 | 31,203,007 | 31,433,777 | 31,675,684 | 31,936,311 |
| | 55% | 54% | 54% | 54% | 54% | 54% | 54% | 54% | 54% | 54% | 54% |
| OG&E DSM | 332 | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |
| Net Load Responsibility (MW) | 5,886 | 5,898 | 5,916 | 5,900 | 5,924 | 5,931 | 5,968 | 5,978 | 6,000 | 6,001 | 6,041 |
| | | 0.20% | 0.32% | -0.27% | 0.41% | 0.12% | 0.62% | 0.17% | 0.37% | 0.01% | 0.67% |
| DSM Adjusted Load Factor | 29,449,054 | 29,166,530 | 29,386,822 | 29,546,604 | 29,703,225 | 29,886,924 | 30,022,974 | 30,137,617 | 30,281,057 | 30,431,239 | 30,604,479 |
| | 57% | 56% | 57% | 57% | 57% | 58% | 57% | 58% | 58% | 58% | 58% |

5.3 Peak Demand Forecast Uncertainty

Table 13 illustrates mapping between event (peak demand) occurrence and the occurrence probability. The median load projections come from the 50th percentile of the distribution. This means that half of the time the peak load would be expected to exceed this level and half of the time the peak load would be below this level.

Table 13 – Probability Assignments

| Event Occurrence | Occurrence Probability |
|--------------------|------------------------|
| 1 out of 30 years | 3% |
| 1 out of 10 years | 10% |
| 1 out of 4 years | 25% |
| 1 out of 2 years | 50% |
| 3 out of 4 years | 75% |
| 9 out of 10 years | 90% |
| 29 out of 30 years | 97% |

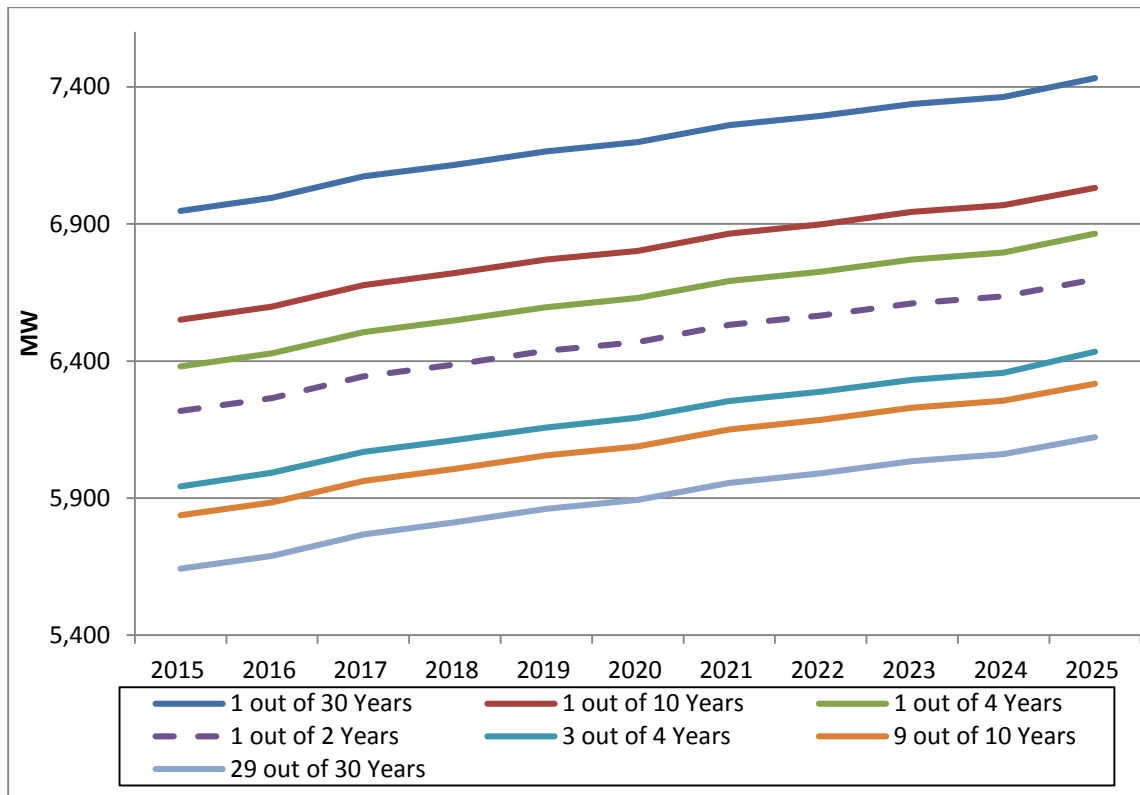
Table 14 and Figure 3 summarize the peak load model forecasts with a 97% confidence interval around potential weather events, assuming no changes in the expected economic outlook. These estimates include wholesale loads and the assumption of expiring wholesale contracts. Following the probability assignments in Table 13, the interpretation of these results is as follows. The *1 out of 2 years* or “expected” forecast shows the peak demand level given the 50th percentile of the load forecast distribution, using all available historical weather data. In this case, there is a 50% probability the peak load will reach this load level or higher.

Table 14 – Peak Demand (MW) Model Forecasts by Weather Probability

| Year | 1 out of 30 Years | 1 out of 10 Years | 1 out of 4 Years | 1 out of 2 Years | 3 out of 4 Years | 9 out of 10 Years | 29 out of 30 Years |
|------|-------------------|-------------------|------------------|------------------|------------------|-------------------|--------------------|
| 2015 | 6,948 | 6,551 | 6,380 | 6,218 | 5,943 | 5,837 | 5,642 |
| 2016 | 6,995 | 6,598 | 6,428 | 6,265 | 5,992 | 5,884 | 5,689 |
| 2017 | 7,073 | 6,677 | 6,505 | 6,344 | 6,069 | 5,963 | 5,768 |
| 2018 | 7,116 | 6,721 | 6,548 | 6,388 | 6,111 | 6,007 | 5,812 |
| 2019 | 7,164 | 6,770 | 6,597 | 6,437 | 6,158 | 6,056 | 5,861 |
| 2020 | 7,198 | 6,802 | 6,630 | 6,469 | 6,194 | 6,088 | 5,893 |
| 2021 | 7,260 | 6,865 | 6,692 | 6,532 | 6,254 | 6,151 | 5,956 |
| 2022 | 7,294 | 6,899 | 6,726 | 6,566 | 6,288 | 6,185 | 5,990 |
| 2023 | 7,338 | 6,944 | 6,770 | 6,611 | 6,331 | 6,230 | 6,035 |
| 2024 | 7,363 | 6,969 | 6,795 | 6,636 | 6,357 | 6,255 | 6,060 |
| 2025 | 7,432 | 7,031 | 6,865 | 6,698 | 6,434 | 6,317 | 6,122 |

The *1 out of 10 years* forecast, which is approximately 300 MW higher than the *1 out of 2 years* case, shows the estimated peak demand under a more extreme weather event that occurs just 10% of the time. Put differently, over a 10-year planning horizon, it is likely that OG&E will reach a summer peak consistent with the *1 out of 10 years* forecast at least once.

Figure 3 – Peak Demand Model Forecasts by Weather Probability



Weather conditions will vary markedly from one year to the next. Consequently, the weather impact on peak demand will also vary considerably from year to year. Dramatic weather condition changes have much more impact on year-to-year differences in demand than economic growth. Overall, the 97% confidence interval associated with weather conditions represents a significant source of risk responsible for approximately 1,300 MW of potential peak load variability in 2025.

6 Retail Customer Forecast

KEY TAKEAWAYS:

- *Total retail customers increases by an average of 1.02% per year*
- *The forecasted total number of retail customers in 2025 is 898,207*

The retail customer forecast is generated from a regression analysis of historical customer growth and economic growth patterns. Approximately five to ten models were estimated for each segment, with 2013 data held as an “out-of-sample” forecasting test period. Table 15 illustrates the final model variables used for the Oklahoma and Arkansas retail customer forecasts, respectively.

Table 15 – Customer Model Drivers

| Economic Drivers and Models | | | Economic Driver Average Annual Growth Rates | | |
|-----------------------------|------------------|---------------------------------------|---|-----------|-----------|
| | | | 2004 - 2014 | 2015-2020 | 2021-2025 |
| Oklahoma | Residential | OKC Population | 1.53% | 1.30% | 1.31% |
| | Commercial | OKC Population | 1.53% | 1.30% | 1.31% |
| | Industrial | OKC Manufacturing Employment | -0.51% | 1.26% | -0.55% |
| | Petroleum | 2014 EIA Nominal Natural Gas Forecast | 0.50% | 4.70% | 3.94% |
| | Street Lighting | OKC Population | 1.53% | 1.30% | 1.31% |
| | Public Authority | OKC Population | 1.53% | 1.30% | 1.31% |
| Arkansas - Ft. Smith | Residential | Population | 0.62% | 0.38% | 0.50% |
| | Commercial | Population | 0.62% | 0.38% | 0.50% |
| | Industrial | Manufacturing Employment | -3.93% | -2.23% | -2.78% |
| | Petroleum | 2014 EIA Nominal Natural Gas Forecast | 0.50% | 4.70% | 3.94% |
| | Street Lighting | Population | 0.62% | 0.38% | 0.50% |
| | Public Authority | Government Employment | 1.59% | 1.04% | 0.87% |

Table 16 summarizes the 2015 annual retail customer forecast by sector and state, and for the company as a whole.

Table 16 – Retail Customer Forecast

| | | Residential | Commercial | Industrial | Oil Field | Street Lighting | Public Authority | Total |
|--------------------|------|-------------|------------|------------|-----------|-----------------|------------------|---------|
| Oklahoma Customers | 2015 | 639,163 | 82,190 | 2,561 | 6,406 | 225 | 14,910 | 745,456 |
| | 2016 | 647,099 | 83,394 | 2,598 | 6,403 | 226 | 15,973 | 755,693 |
| | 2017 | 654,850 | 84,249 | 2,658 | 6,378 | 227 | 16,605 | 764,968 |
| | 2018 | 661,707 | 85,130 | 2,695 | 6,357 | 227 | 16,991 | 773,108 |
| | 2019 | 668,764 | 86,090 | 2,716 | 6,338 | 228 | 17,400 | 781,534 |
| | 2020 | 675,359 | 87,005 | 2,728 | 6,322 | 228 | 17,787 | 789,429 |
| | 2021 | 681,933 | 87,930 | 2,734 | 6,308 | 228 | 18,179 | 797,313 |
| | 2022 | 688,700 | 88,893 | 2,737 | 6,296 | 229 | 18,586 | 805,441 |
| | 2023 | 695,635 | 89,886 | 2,737 | 6,286 | 229 | 19,006 | 813,779 |
| | 2024 | 702,702 | 90,901 | 2,736 | 6,277 | 230 | 19,434 | 822,281 |
| | 2025 | 709,963 | 91,948 | 2,735 | 6,270 | 230 | 19,876 | 831,021 |
| Arkansas Customers | 2015 | 54,841 | 8,948 | 348 | 44 | 26 | 1,525 | 65,732 |
| | 2016 | 54,723 | 8,918 | 351 | 48 | 26 | 1,517 | 65,583 |
| | 2017 | 54,590 | 8,897 | 350 | 53 | 26 | 1,527 | 65,444 |
| | 2018 | 54,629 | 8,935 | 349 | 54 | 26 | 1,544 | 65,537 |
| | 2019 | 54,797 | 9,005 | 348 | 55 | 26 | 1,557 | 65,787 |
| | 2020 | 54,972 | 9,070 | 346 | 55 | 26 | 1,571 | 66,040 |
| | 2021 | 55,108 | 9,119 | 344 | 55 | 26 | 1,589 | 66,241 |
| | 2022 | 55,250 | 9,168 | 342 | 55 | 27 | 1,602 | 66,444 |
| | 2023 | 55,409 | 9,221 | 340 | 55 | 27 | 1,617 | 66,669 |
| | 2024 | 55,589 | 9,280 | 338 | 55 | 27 | 1,632 | 66,921 |
| | 2025 | 55,780 | 9,342 | 336 | 55 | 27 | 1,646 | 67,186 |
| Total Customers | 2015 | 694,004 | 91,138 | 2,909 | 6,450 | 251 | 16,436 | 811,188 |
| | 2016 | 701,822 | 92,312 | 2,949 | 6,451 | 253 | 17,490 | 821,277 |
| | 2017 | 709,441 | 93,146 | 3,009 | 6,431 | 253 | 18,132 | 830,412 |
| | 2018 | 716,335 | 94,065 | 3,044 | 6,411 | 254 | 18,535 | 838,644 |
| | 2019 | 723,561 | 95,094 | 3,063 | 6,393 | 254 | 18,956 | 847,322 |
| | 2020 | 730,330 | 96,075 | 3,073 | 6,377 | 255 | 19,358 | 855,469 |
| | 2021 | 737,041 | 97,050 | 3,078 | 6,363 | 255 | 19,768 | 863,555 |
| | 2022 | 743,950 | 98,061 | 3,079 | 6,351 | 255 | 20,188 | 871,885 |
| | 2023 | 751,045 | 99,107 | 3,077 | 6,341 | 256 | 20,623 | 880,448 |
| | 2024 | 758,291 | 100,181 | 3,074 | 6,332 | 256 | 21,066 | 889,202 |
| | 2025 | 765,742 | 101,290 | 3,071 | 6,325 | 257 | 21,522 | 898,207 |

Table 17 summarizes the 2015 annual retail customer growth rate forecast by sector and state, and for the company as a whole.

Table 17 – Customer Growth Rates

| | | Residential | Commercial | Industrial | Oil Field | Street Lighting | Public Authority | Total |
|------------------------------------|------|-------------|------------|------------|-----------|-----------------|------------------|--------|
| Oklahoma Customers | 2016 | 1.24% | 1.46% | 1.43% | -0.05% | 0.62% | 7.13% | 1.37% |
| | 2017 | 1.20% | 1.03% | 2.33% | -0.39% | 0.26% | 3.96% | 1.23% |
| | 2018 | 1.05% | 1.05% | 1.38% | -0.34% | 0.16% | 2.33% | 1.06% |
| | 2019 | 1.07% | 1.13% | 0.76% | -0.30% | 0.17% | 2.40% | 1.09% |
| | 2020 | 0.99% | 1.06% | 0.44% | -0.25% | 0.16% | 2.23% | 1.01% |
| | 2021 | 0.97% | 1.06% | 0.23% | -0.22% | 0.16% | 2.20% | 1.00% |
| | 2022 | 0.99% | 1.09% | 0.12% | -0.19% | 0.17% | 2.24% | 1.02% |
| | 2023 | 1.01% | 1.12% | 0.00% | -0.16% | 0.18% | 2.26% | 1.04% |
| | 2024 | 1.02% | 1.13% | -0.03% | -0.14% | 0.18% | 2.26% | 1.04% |
| | 2025 | 1.03% | 1.15% | -0.05% | -0.12% | 0.18% | 2.27% | 1.06% |
| Arkansas Customers | 2016 | -0.22% | -0.33% | 0.89% | 9.19% | 0.59% | -0.52% | -0.23% |
| | 2017 | -0.24% | -0.24% | -0.15% | 9.74% | 0.21% | 0.63% | -0.21% |
| | 2018 | 0.07% | 0.42% | -0.34% | 3.21% | 0.19% | 1.09% | 0.14% |
| | 2019 | 0.31% | 0.79% | -0.50% | 1.17% | 0.32% | 0.84% | 0.38% |
| | 2020 | 0.32% | 0.73% | -0.53% | 0.47% | 0.29% | 0.92% | 0.38% |
| | 2021 | 0.25% | 0.54% | -0.54% | 0.22% | 0.22% | 1.13% | 0.31% |
| | 2022 | 0.26% | 0.53% | -0.55% | 0.10% | 0.22% | 0.84% | 0.31% |
| | 2023 | 0.29% | 0.58% | -0.58% | 0.05% | 0.24% | 0.93% | 0.34% |
| | 2024 | 0.32% | 0.64% | -0.57% | 0.05% | 0.26% | 0.91% | 0.38% |
| | 2025 | 0.34% | 0.67% | -0.55% | 0.04% | 0.28% | 0.89% | 0.40% |
| Total Customer Growth Rates | 2016 | 1.13% | 1.29% | 1.36% | 0.01% | 0.62% | 6.42% | 1.24% |
| | 2017 | 1.09% | 0.90% | 2.04% | -0.31% | 0.25% | 3.67% | 1.11% |
| | 2018 | 0.97% | 0.99% | 1.18% | -0.31% | 0.16% | 2.22% | 0.99% |
| | 2019 | 1.01% | 1.09% | 0.62% | -0.28% | 0.19% | 2.27% | 1.03% |
| | 2020 | 0.94% | 1.03% | 0.33% | -0.25% | 0.18% | 2.12% | 0.96% |
| | 2021 | 0.92% | 1.01% | 0.14% | -0.22% | 0.17% | 2.12% | 0.95% |
| | 2022 | 0.94% | 1.04% | 0.04% | -0.18% | 0.18% | 2.13% | 0.96% |
| | 2023 | 0.95% | 1.07% | -0.06% | -0.16% | 0.18% | 2.15% | 0.98% |
| | 2024 | 0.96% | 1.08% | -0.09% | -0.14% | 0.19% | 2.15% | 0.99% |
| | 2025 | 0.98% | 1.11% | -0.10% | -0.12% | 0.19% | 2.16% | 1.01% |

Appendix A – Data Sources

OG&E's service territory encompasses approximately half of Oklahoma and a small area in western Arkansas, including and surrounding Ft. Smith. Historical data sources used to estimate the econometric equations and prepare the 2015 forecast fall into the following categories:

- OG&E company data (energy sales, revenue, load responsibility peak demand and weather-normal degree days);
- Constructed variables for the models (usually binary variables);
- Weather information;
- Economic and demographic data from the Center for Applied Economic Research at Oklahoma State University; and
- Energy Efficiency impacts based on expected national standards for appliances and equipment from the Appliance Standard Awareness Project (ASAP).

This section describes each of these categories and the types of variables used in the econometric models.

Internal Information

Sales, Revenue and Customers

OG&E's Accounting Department provides sales (MWh), revenue, and customer data by revenue class. This information is recorded in the monthly energy sales report for both Oklahoma and Arkansas jurisdictions. The monthly energy sales report (by state) contains information from the 1970s to the present. The six revenue classes are: Residential, Commercial, Industrial, Oil Field, Street Lighting and Public Authority.

Retail Electric Prices

In the econometric models with statistically significant electric price variables, the historical values of the variables are defined as “average” prices (energy revenues divided by energy sales). The retail electric prices used in the (forward-looking) forecast include the revised cost of operations along with riders for various other projects. Overall, the expected increases in retail prices are higher than those in the 2014 forecast, due to the inclusion of certain environmental controls. The cumulative increase in price over ten years in the 2015 forecast is 26%. Averaging the estimated annual changes in price yields an approximately 2.1% annual increase in the average price per kWh.

Load Responsibility

The peak load forecasts are obtained based on historical “Normalized Load Responsibility” data (defined as the System Load minus OMPA Total Load plus OMPA PSA¹ plus Load Curtailment plus real-time pricing (RTP) induced self-generation). The normalized load responsibility series

¹ OMPA PSA contract terminated 12/31/2013 and is removed from forecast at that time due to the absence of an Evergreen clause in the contract.

was further adjusted for peak demand modeling purposes by subtracting variable OMPA PSA loads and forecasting these directly as wholesale FERC loads.

Weather Normalized Cooling Degree Days and Heating Degree Days

OG&E's Pricing Department provides the weather-normal monthly Cooling Degree Days and Heating Degree Days (see definitions below), which are factors in developing the energy forecast for future years. The weather-normalized CDD and HDD values are based on 30 rolling years of weather history from selected weather stations in the OG&E service territory.

Information Obtained from External Sources

Weather Data

OG&E obtained the following information from the Department of Commerce, NOAA:

- Cooling-degree days (CDD).
- Heating-degree days (HDD).
- A variety of hourly weather indicators, including temperature, humidity, dew point, precipitation, wind speed, and cloud cover.

NOAA's definition of HDD is 65° minus the average of the high and low temperatures of the day (or zero if the average of the high and low temperatures is greater than 65°). The definition of CDD is the average of the high and low temperatures of the day minus 65° (or zero if the average of the high and low temperatures of the day is less than 65°). HDD and CDD for Ft. Smith and Oklahoma City have been used in weather-sensitive sales forecasting equations. Hourly weather data from these stations, and from Guthrie, Stillwater, and Muskogee, were used to model and forecast peak loads.

Economic and Demographic Data

OG&E purchases economic and demographic data from Oklahoma State University. The data include historical and forecasted time series used in the econometric models; these data include population, real income, wages and salaries, price deflators, various production and output series, including industrial production, gross state product, natural gas prices, and employment.

In 2007 the Oklahoma economic driver series were adjusted for structural changes in the state's economy. OSU's research had revealed a "billionaire" effect that inflates the real income and gross state product series that are critically important in forecasting OG&E's energy sales.

The table below compares the growth rates of 2014 and 2015 forecast drivers. The "ex-energy" variables, where the "billionaire" effect is removed, are compared to their unadjusted counterparts. The comparison reveals that the difference in growth rates between the ex-energy series and their counterpart is still a significant factor.

Economic Driver Growth Rate Comparison

| Economic Drivers | Drivers Average Growth Rate | | | | | |
|------------------------------------|-------------------------------|------------------------|-------------------------------|------------------------|-------------------------------|------------------------|
| | Current Forecast 2015 to 2025 | Last Year 2015 to 2025 | Current Forecast 2015 to 2020 | Last Year 2015 to 2020 | Current Forecast 2021 to 2025 | Last Year 2021 to 2025 |
| Real Personal Income OKC | 4.28% | 4.21% | 4.44% | 4.59% | 4.09% | 3.75% |
| Real Personal Income Ex Energy OKC | 2.17% | 2.67% | 2.66% | 3.30% | 1.58% | 1.91% |

National Energy Efficiency Codes and Standards Impact Data

The Appliance Standards Awareness Project (ASAP) compiles energy efficiency information about expected appliance and equipment codes and standards, including expected implementation dates and expected energy efficiency impacts. OG&E downloaded state-level data from the ASAP website, <http://www.appliance-standards.org/>, and scaled the expected state-level impacts for the OG&E service territory. The scaled energy efficiency impacts have been included in the baseline retail energy forecast.

Appendix B – Expected DSM Program Impacts

Demand Side Management (DSM) is designed to reduce the load requirements on the system. This appendix shares OG&E's history with DSM and highlights the current efforts that are included in this load forecast.

Programs at OG&E

OG&E has successfully managed many energy efficiency and demand response offerings during the past 30 years. As far back as the late 1970's, OG&E experienced wide spread acceptance of its in-home energy audit program, known as AWARD, that paid customers to make home energy improvements. OG&E had strong participation in its direct load control residential air conditioning program, known as PEAKS, in the 1980's. OG&E currently offers price response options as well as Day-Ahead Pricing, curtailable and interruptible rate tariffs (which have been in operation since 1997), and several time-of-use tariffs (some of which have been offered since 1985). In addition, OG&E introduced a successful ENERGY STAR® New Home Program in 1996 and continues a new home construction program today. Participation in these programs indicates customers are interested in lowering energy consumption and managing energy use.

OG&E filed a Quick Start Program in Oklahoma Cause No. PUD 200800059 which was in effect until December 31, 2009. The Quick Start Program allowed OG&E to quickly begin offering programs for all classes of customers primarily by providing rebates to help increase customer awareness and to help accelerate market transformation of products such as compact fluorescent lamps. OG&E's first comprehensive portfolio of Demand Programs under Subchapter 41 was approved by the Oklahoma Corporation Commission in Cause No. PUD 200900200 for implementation in years 2010-2012. OG&E's most recent Demand Portfolio was approved by the Commission in Cause No. PUD 201200134 for implementation in years 2013-2015. Since the inception of the QuickStart Program in 2008 through the end of 2014, OG&E has secured a total of 174 MW of demand savings and 374,010 MWh of energy savings. In Arkansas OG&E's Energy Efficiency Cost Recovery (EECR) rider focuses on weatherization, education and commercial customer energy efficiency efforts. Through the end of 2014, OG&E has secured a total of 12 MW of demand savings and 51,942 MWh of energy savings.

a. Home Energy Efficiency Program (HEEP)

This program, available to Oklahoma customers, consists of a home assessment targeted to residential customers who need assistance in identifying areas to improve in both thermal and technology efficiencies. Assistance is offered for air conditioning tune ups, duct repair and inducements offered for additional attic insulation installed. Expansions for the program in 2016 include more options and are expected to increase adoption of energy saving measures for residential customers including hard-to-reach customers, multi-family units and manufactured housing units.

b. Positive Energy-New Home Construction Program (PE-NHC)

This program encourages builders and homeowners in Oklahoma to utilize energy efficient Positive Energy-New Home Construction practices by installing higher level than required thermal packages in the construction of new homes. Builders will be paid inducements to bring new homes to the higher standards. These homes will be rated and certified by OG&E. This certification allows homebuilders to apply for available tax credits as a result of these upgrades.

c. Weatherization Residential Assistance Program (WRAP)

This program is designed to provide assistance to both lower and fixed income customers by engaging licensed contractors to make improvements to the thermal envelope and to inspect and tune up mechanical equipment in their homes. This work allows customers to better manage energy usage, improve their comfort and makes the living space safer. A similar program is offered in Arkansas.

d. Commercial Energy Efficiency Program (CEEP)

This program is targeted to medium and large commercial customers for the purpose of allowing them to pursue EE projects unique to their business. Inducements will be paid for kW reduced by these customers. The 2016 program consolidates once stand-alone programs and/or measures (e.g. Commercial Lighting Program, Industrial Energy Efficiency Program) under one umbrella. This offering of multiple energy savings measures and targeted programs will help address the needs of a wider variety of commercial and industrial customers. A similar program is offered in Arkansas.

e. Integrated Volt Var Control (IVVC)

The IVVC Program is a system of devices, controls, software and communications products used to manage OG&E's distribution system reactive power flow and voltage level. This technology is used to reduce energy demand during peak periods and minimize losses, while ensuring acceptable customer voltage levels. During non-peak periods, Volt Var Optimization (VVO) will normally operate in loss reduction mode. In loss reduction mode VVO compensates for inefficiencies caused by reactive loads such as electric motors. As a result, energy loss reductions (i.e. energy savings) are expected to be realized during non-peak periods. VVO will be placed in demand reduction or combined loss/demand reduction mode when needed to help reduce system peak energy demand. Demand reduction mode reduces voltage in order to achieve a corresponding reduction in peak energy consumption. Based on study results achieved to date, a peak demand reduction of approximately 2% has been achieved across the circuits on which this technology has been deployed. Over the next 10 years, IVVC is expected to reduce OG&E's load requirement by 82 MW.

f. Load Reduction Rider

The Load Reduction program offers financial incentives to commercial and industrial customers that can reduce their electrical load when notified by OG&E. Customers subscribe to an amount of demand reduction (200kW and above) and then receive a discount for that promised reduction. Those who reduce their usage during a called event receive a discount on their next

electric bill. OG&E continues to grow this program and plans to achieve over 130 MW reduction by 2025.

g. SmartHours

The SmartHours program integrates technology and pricing to help customers reduce energy usage at peak times. The program utilizes the Advanced Metering Infrastructure (AMI) to securely send price signals across the network and through the smart meter, directly to the Programmable Communicating Thermostat (PCT). Signals are also sent via text message and email. Customers respond to these price signals between the weekday hours of 2:00 p.m. and 7:00 p.m. over the four summer months of June, July, August and September and help reduce the peak demand on the system. In 2015 the Company will achieve the goal of enrolling a approximately 20% of residential customers into the SmartHours program. Likewise, commercial and industrial customers will be able to take advantage of more price response programs in the future with an overall combined system coincident peak demand reduction of approximately 150 MW.

DSM Forecast

Historical savings from previous programs are already imbedded in the load forecast. New programs need to be subtracted from the load forecast. The Oklahoma Comprehensive Energy Efficiency Programs and the Arkansas Comprehensive Plan for Energy Efficiency Programs that are not yet included in the load forecast and need to be subtracted along with any future EE plans.

Forecasted Energy Reduction from OG&E DSM Programs

| Energy (GWh) | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------------------|------|------|------|------|------|------|------|-------|-------|-------|-------|
| Current Portfolio | 318 | 318 | 318 | 318 | 317 | 316 | 313 | 307 | 300 | 293 | 285 |
| 2016 Portfolio: EE | - | 94 | 191 | 294 | 294 | 294 | 293 | 292 | 290 | 286 | 281 |
| 2019 Portfolio: EE | - | - | - | - | 101 | 198 | 301 | 301 | 301 | 300 | 299 |
| 2022 Portfolio: EE | - | - | - | - | - | - | - | 101 | 198 | 301 | 301 |
| 2025 Portfolio: EE | - | - | - | - | - | - | - | - | - | - | 101 |
| IVVC | 21 | 25 | 29 | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 33 |
| LRR | 3 | 3 | 4 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 |
| Smart Hours | 20 | 21 | 21 | 22 | 23 | 23 | 24 | 25 | 25 | 25 | 26 |
| Total Net Energy Reduction | 362 | 461 | 563 | 672 | 773 | 869 | 970 | 1,065 | 1,153 | 1,244 | 1,332 |

Forecasted Peak Demand Reduction from OG&E DSM Programs

| Demand (MW) | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|----------------------------|------|------|------|------|------|------|------|------|------|------|------|
| Current Portfolio | 81 | 81 | 81 | 81 | 81 | 80 | 79 | 78 | 76 | 74 | 72 |
| 2016 Portfolio: EE | - | 20 | 42 | 66 | 66 | 66 | 66 | 65 | 65 | 64 | 63 |
| 2019 Portfolio: EE | - | - | - | - | 22 | 44 | 68 | 68 | 68 | 67 | 67 |
| 2022 Portfolio: EE | - | - | - | - | - | - | - | 22 | 44 | 68 | 68 |
| 2025 Portfolio: EE | - | - | - | - | - | - | - | - | - | - | 22 |
| IVVC | 41 | 54 | 67 | 82 | 82 | 82 | 82 | 82 | 82 | 82 | 82 |
| LRR | 60 | 62 | 88 | 109 | 112 | 116 | 119 | 123 | 126 | 130 | 133 |
| Smart Hours | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| Total Net Demand Reduction | 332 | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |

Appendix C – Distributed Generation (DG) Considerations

DG is defined as electricity production that is on premise or close to the customer load and is interconnected to the utility distribution system. The most common DG technologies currently being adopted include solar photovoltaic, fuel cells and micro-turbines. In most applications, DG can be a substitute product for grid-supplied electricity.

DG growth is increasing in certain states due to policies favorable to DG, tax incentives, state-level equipment rebates and relatively high electricity prices. However, due to regional economic and policy conditions, the near-term impacts of DG on load in OG&E's service territory are not estimated to be material. Although the rate of DG installations on OG&E's system is very low at this time, market conditions will continue to be monitored going forward.

Appendix B – Portfolio Annual Cost Components

Portfolio Annual Cost Components

| | Scrub/ Convert | | | | Scrub | | | | Convert | | | |
|-------------|---------------------|----------|------------------------------------|---------------|---------------------|----------|------------------------------------|---------------|---------------------|----------|------------------------------------|---------------|
| | Return on Rate Base | Expenses | Production Cost with Market Impact | Customer Cost | Return on Rate Base | Expenses | Production Cost with Market Impact | Customer Cost | Return on Rate Base | Expenses | Production Cost with Market Impact | Customer Cost |
| 2015 | 17 | 282 | 864 | 1,163 | 21 | 283 | 864 | 1,168 | 13 | 282 | 864 | 1,158 |
| 2016 | 38 | 254 | 905 | 1,197 | 55 | 256 | 905 | 1,216 | 23 | 252 | 905 | 1,181 |
| 2017 | 76 | 263 | 947 | 1,286 | 105 | 265 | 947 | 1,317 | 51 | 260 | 947 | 1,258 |
| 2018 | 136 | 273 | 998 | 1,407 | 175 | 283 | 1,009 | 1,466 | 99 | 260 | 986 | 1,345 |
| 2019 | 193 | 272 | 1,156 | 1,622 | 242 | 322 | 1,080 | 1,643 | 144 | 231 | 1,233 | 1,607 |
| 2020 | 212 | 322 | 1,152 | 1,687 | 264 | 391 | 1,078 | 1,733 | 162 | 260 | 1,230 | 1,652 |
| 2021 | 210 | 352 | 1,194 | 1,757 | 258 | 424 | 1,115 | 1,797 | 162 | 297 | 1,277 | 1,736 |
| 2022 | 223 | 345 | 1,225 | 1,793 | 269 | 421 | 1,150 | 1,840 | 178 | 276 | 1,305 | 1,758 |
| 2023 | 254 | 344 | 1,262 | 1,860 | 297 | 428 | 1,188 | 1,913 | 211 | 275 | 1,347 | 1,833 |
| 2024 | 267 | 373 | 1,300 | 1,941 | 308 | 452 | 1,217 | 1,977 | 227 | 303 | 1,393 | 1,924 |
| 2025 | 259 | 406 | 1,356 | 2,020 | 297 | 490 | 1,269 | 2,056 | 220 | 337 | 1,457 | 2,015 |
| 2026 | 255 | 407 | 1,428 | 2,090 | 291 | 486 | 1,335 | 2,112 | 218 | 339 | 1,528 | 2,085 |
| 2027 | 268 | 467 | 1,480 | 2,216 | 302 | 539 | 1,382 | 2,223 | 234 | 416 | 1,597 | 2,247 |
| 2028 | 302 | 473 | 1,557 | 2,331 | 333 | 540 | 1,454 | 2,328 | 270 | 414 | 1,664 | 2,348 |
| 2029 | 313 | 463 | 1,602 | 2,378 | 342 | 543 | 1,483 | 2,368 | 283 | 398 | 1,725 | 2,406 |
| 2030 | 298 | 481 | 1,693 | 2,472 | 325 | 571 | 1,564 | 2,461 | 271 | 403 | 1,837 | 2,511 |
| 2031 | 287 | 510 | 1,836 | 2,633 | 311 | 577 | 1,708 | 2,597 | 261 | 463 | 1,974 | 2,699 |
| 2032 | 283 | 489 | 1,921 | 2,693 | 305 | 568 | 1,772 | 2,645 | 260 | 420 | 2,086 | 2,766 |
| 2033 | 302 | 517 | 2,043 | 2,862 | 322 | 592 | 1,882 | 2,796 | 281 | 461 | 2,211 | 2,954 |
| 2034 | 352 | 513 | 2,153 | 3,018 | 370 | 597 | 1,988 | 2,954 | 333 | 441 | 2,329 | 3,103 |
| 2035 | 401 | 526 | 2,237 | 3,164 | 416 | 628 | 2,056 | 3,100 | 384 | 445 | 2,451 | 3,280 |
| 2036 | 448 | 546 | 2,356 | 3,350 | 462 | 644 | 2,150 | 3,255 | 434 | 460 | 2,576 | 3,471 |
| 2037 | 495 | 596 | 2,417 | 3,507 | 506 | 705 | 2,215 | 3,426 | 482 | 511 | 2,631 | 3,624 |
| 2038 | 541 | 583 | 2,556 | 3,680 | 550 | 687 | 2,343 | 3,580 | 531 | 491 | 2,793 | 3,814 |
| 2039 | 589 | 646 | 2,625 | 3,861 | 596 | 743 | 2,411 | 3,750 | 581 | 569 | 2,875 | 4,025 |
| 2040 | 639 | 657 | 2,801 | 4,097 | 644 | 765 | 2,581 | 3,991 | 632 | 562 | 3,029 | 4,223 |
| 2041 | 691 | 690 | 2,905 | 4,287 | 695 | 803 | 2,654 | 4,153 | 686 | 603 | 3,165 | 4,454 |
| 2042 | 759 | 741 | 3,077 | 4,577 | 762 | 845 | 2,814 | 4,420 | 755 | 649 | 3,367 | 4,771 |
| 2043 | 824 | 770 | 3,262 | 4,856 | 826 | 846 | 3,134 | 4,805 | 821 | 676 | 3,533 | 5,030 |
| 2044 | 819 | 821 | 3,361 | 5,001 | 820 | 840 | 3,346 | 5,006 | 817 | 728 | 3,682 | 5,227 |
| 30 Yr NPVRR | 2,596 | 4,216 | 15,540 | 22,351 | 2,919 | 4,821 | 14,683 | 22,423 | 2,276 | 3,699 | 16,509 | 22,484 |

| | Scrub/ Replace | | | | Replace | | | |
|-------------|---------------------|----------|------------------------------------|---------------|---------------------|----------|------------------------------------|---------------|
| | Return on Rate Base | Expenses | Production Cost with Market Impact | Customer Cost | Return on Rate Base | Expenses | Production Cost with Market Impact | Customer Cost |
| 2015 | 27 | 284 | 864 | 1,174 | 32 | 284 | 864 | 1,180 |
| 2016 | 62 | 257 | 905 | 1,223 | 70 | 258 | 905 | 1,232 |
| 2017 | 138 | 269 | 947 | 1,354 | 175 | 275 | 947 | 1,397 |
| 2018 | 263 | 284 | 998 | 1,545 | 352 | 285 | 986 | 1,624 |
| 2019 | 353 | 297 | 1,100 | 1,750 | 463 | 284 | 1,120 | 1,866 |
| 2020 | 365 | 380 | 1,093 | 1,838 | 466 | 378 | 1,113 | 1,957 |
| 2021 | 355 | 402 | 1,133 | 1,891 | 452 | 397 | 1,155 | 2,003 |
| 2022 | 362 | 404 | 1,164 | 1,931 | 454 | 395 | 1,183 | 2,033 |
| 2023 | 386 | 402 | 1,201 | 1,988 | 475 | 392 | 1,224 | 2,090 |
| 2024 | 394 | 433 | 1,238 | 2,064 | 478 | 424 | 1,269 | 2,170 |
| 2025 | 379 | 462 | 1,289 | 2,130 | 460 | 450 | 1,325 | 2,235 |
| 2026 | 369 | 465 | 1,362 | 2,196 | 447 | 454 | 1,396 | 2,296 |
| 2027 | 377 | 504 | 1,413 | 2,294 | 451 | 489 | 1,462 | 2,402 |
| 2028 | 405 | 515 | 1,487 | 2,407 | 475 | 499 | 1,525 | 2,500 |
| 2029 | 410 | 508 | 1,529 | 2,447 | 478 | 489 | 1,578 | 2,544 |
| 2030 | 390 | 542 | 1,612 | 2,544 | 454 | 526 | 1,675 | 2,654 |
| 2031 | 373 | 540 | 1,755 | 2,668 | 433 | 525 | 1,812 | 2,770 |
| 2032 | 364 | 538 | 1,838 | 2,739 | 420 | 518 | 1,920 | 2,858 |
| 2033 | 377 | 550 | 1,960 | 2,887 | 431 | 529 | 2,044 | 3,003 |
| 2034 | 422 | 563 | 2,070 | 3,055 | 471 | 543 | 2,162 | 3,176 |
| 2035 | 464 | 584 | 2,148 | 3,196 | 511 | 560 | 2,272 | 3,342 |
| 2036 | 506 | 608 | 2,268 | 3,382 | 549 | 585 | 2,399 | 3,534 |
| 2037 | 547 | 652 | 2,325 | 3,524 | 586 | 624 | 2,447 | 3,658 |
| 2038 | 588 | 647 | 2,467 | 3,701 | 623 | 618 | 2,616 | 3,857 |
| 2039 | 632 | 690 | 2,535 | 3,857 | 665 | 656 | 2,694 | 4,015 |
| 2040 | 679 | 720 | 2,716 | 4,115 | 711 | 690 | 2,859 | 4,259 |
| 2041 | 729 | 748 | 2,822 | 4,299 | 759 | 720 | 2,998 | 4,477 |
| 2042 | 793 | 798 | 2,993 | 4,584 | 822 | 764 | 3,199 | 4,785 |
| 2043 | 856 | 846 | 3,185 | 4,887 | 883 | 809 | 3,380 | 5,072 |
| 2044 | 848 | 916 | 3,282 | 5,045 | 874 | 878 | 3,524 | 5,276 |
| 30 Yr NPVRR | 3,602 | 4,623 | 15,005 | 23,229 | 4,282 | 4,515 | 15,439 | 24,237 |

Appendix C – Portfolio Annual Emissions

Portfolio Annual Emissions

| | Scrub/ Convert | | | Scrub | | | Convert | | |
|------|----------------|------------|-------------------|-------------|------------|-------------------|-------------|------------|-------------------|
| | CO2 (ktons) | SO2 (tons) | Annual NOx (tons) | CO2 (ktons) | SO2 (tons) | Annual NOx (tons) | CO2 (ktons) | SO2 (tons) | Annual NOx (tons) |
| 2015 | 18,113 | 43,677 | 17,686 | 18,113 | 43,677 | 17,686 | 18,113 | 43,677 | 17,686 |
| 2016 | 15,949 | 37,615 | 13,286 | 15,949 | 37,615 | 13,286 | 15,949 | 37,615 | 13,286 |
| 2017 | 17,775 | 42,282 | 14,746 | 17,775 | 42,282 | 14,746 | 17,775 | 42,282 | 14,746 |
| 2018 | 19,532 | 36,703 | 15,777 | 19,385 | 28,962 | 15,672 | 19,675 | 45,257 | 15,879 |
| 2019 | 12,207 | 11,126 | 10,830 | 18,476 | 13,156 | 15,210 | 6,289 | 9,208 | 6,706 |
| 2020 | 13,957 | 10,980 | 11,298 | 20,826 | 13,190 | 16,126 | 7,219 | 8,802 | 6,589 |
| 2021 | 14,101 | 10,908 | 11,229 | 21,281 | 13,230 | 16,251 | 7,605 | 8,790 | 6,726 |
| 2022 | 14,300 | 11,722 | 11,616 | 21,310 | 13,983 | 16,531 | 7,434 | 9,522 | 6,779 |
| 2023 | 14,759 | 11,199 | 11,502 | 21,758 | 13,431 | 16,458 | 7,135 | 8,770 | 6,103 |
| 2024 | 15,916 | 10,872 | 11,430 | 23,338 | 13,248 | 16,668 | 8,397 | 8,474 | 6,111 |
| 2025 | 16,060 | 12,846 | 12,282 | 23,206 | 15,116 | 17,362 | 8,789 | 10,534 | 7,124 |

| | Scrub/ Replace | | | Replace | | |
|------|----------------|------------|-------------------|-------------|------------|-------------------|
| | CO2 (ktons) | SO2 (tons) | Annual NOx (tons) | CO2 (ktons) | SO2 (tons) | Annual NOx (tons) |
| 2015 | 18,113 | 43,677 | 17,686 | 18,113 | 43,677 | 17,686 |
| 2016 | 15,949 | 37,615 | 13,286 | 15,949 | 37,615 | 13,286 |
| 2017 | 17,775 | 42,282 | 14,746 | 17,775 | 42,282 | 14,746 |
| 2018 | 19,532 | 36,703 | 15,777 | 19,675 | 45,257 | 15,879 |
| 2019 | 13,975 | 11,149 | 10,710 | 9,826 | 9,253 | 6,467 |
| 2020 | 16,070 | 11,007 | 11,238 | 11,411 | 8,855 | 6,424 |
| 2021 | 16,282 | 10,936 | 11,114 | 11,925 | 8,845 | 6,441 |
| 2022 | 16,403 | 11,748 | 11,525 | 11,692 | 9,575 | 6,664 |
| 2023 | 17,294 | 11,230 | 11,541 | 12,205 | 8,832 | 6,181 |
| 2024 | 18,361 | 10,902 | 11,420 | 13,312 | 8,534 | 6,125 |
| 2025 | 18,253 | 12,873 | 12,336 | 13,164 | 10,588 | 7,218 |

Appendix D – OG&E 2015 Oklahoma Technical Conference

OG&E 2015 Draft Integrated Resource Plan
Oklahoma Technical Conference
August 25, 2015, Oklahoma City
Meeting Minutes

The Oklahoma Gas & Electric Company (“OG&E”) 2015 Integrated Resource Plan (“IRP”) Technical Conference was held on August 25, 2015 in OG&E’s offices from 9:15 AM to 12:00 PM.¹ The RSVP list and the slide presentation are attached to these minutes. The meeting began with an introduction by Mr. Kimber Shoop, a Senior Attorney at OG&E.

The majority of the meeting was organized around a slide presentation of the 2015 IRP that was made by Mr. Leon Howell, a member of OG&E’s resource planning team. Stakeholders asked clarifying questions throughout the presentation. The second part of the meeting was devoted to stakeholder feedback on OG&E’s 2015 IRP.

Part I: OG&E Presentation & Stakeholder Questions

OG&E began by providing an overview of the fundamental elements of the 2015 IRP that remain unchanged from the 2014 IRP Update. These elements consist of OG&E’s environmental compliance obligations with respect to the Regional Haze and Mercury and Air Toxics Rules (“MATS”) regulations and the modernization of the Mustang Plant. These proposed compliance strategies are unchanged from the 2014 IRP Update.

The presentation then reviewed the 2015 IRP assumptions. Several of these assumptions were updated from the 2014 IRP Update, including: i) the energy forecast; ii) the demand forecast; iii) existing resource capacity; iv) capacity needs; v) emission control technology costs; and vi) fuel forecasts. OG&E noted that the updates to these assumptions do not have a material impact on the analysis contained in the 2014 IRP Update and the action plan remains the same.

Beginning with the energy forecast, the updated forecast dated July of 2015 showed a lower total energy forecast, as well as a lower forecast of demand-side management (“DSM”) resources on a megawatt-hour (“MWh”) basis for the first eight years with a higher forecast in the last two years.² Similarly, OG&E reviewed the total demand forecast which was updated from the 2014 IRP Update, which showed a slight decrease in the demand forecast due to increased DSM capacity. OG&E presented a slide on the updated assumed system peak capacity and explained the updated assumed wind

¹ As required by the IRP rules, OG&E secured the services of a facilitator, Danielle S. Powers. In addition to facilitating the meeting, Ms. Powers prepared these meeting notes.

² The DSM forecast was updated and expanded through 2025 based on actual smart meter data from 2014.

capacity based on the new Southwest Power Pool (“SPP”) criteria for wind, which resulted in a 27 MW increase in wind capacity in OG&E’s resource mix. In response to a question, OG&E clarified that the decreases in capacity across the 10 year forecast period is due to specific unit retirements and the expiration of certain power purchase agreements (“PPAs”).

OG&E presented a slide showing that OG&E would have a capacity need beginning in 2018 as a result of the planned retirement of 460 MW at its Mustang Generating Facility. OG&E also presented a slide that showed how its capacity and energy mix has changed since 2007 and what it is expected to look like in 2019. In response to a question about the Request for Information (“RFI”) recently issued by OG&E for wind resources and the effect of the potential increase in wind resources as a result of the RFI, OG&E responded that wind does not provide much in terms of capacity on the system. In addition, OG&E agreed to consider including demand response (“DR”) as a resource in the generation resource capacity mix in the future.

OG&E presented a slide on the updated emission control technology cost assumptions from the 2014 IRP Update and discussed the status of current efforts to refine these estimates through a bid process via a Request for Proposals (“RFP”). OG&E indicated that some contracts had already been signed for some of the equipment needed for the environmental control projects, and committed to checking the status of the contracts for the environmental control projects presented.

OG&E presented a slide on EIA’s 2015 coal and natural gas price forecast. OG&E explained that there was no material change in gas prices from the 2014 IRP Update. In response to a question about a recent announcement regarding an increase in coal prices, OG&E explained that they do not update forecasts based on short-term market changes, and that OG&E will update their forecasts in the spring of 2016 when the Energy Information Administration (“EIA”) releases their updated forecast. Also, in response to a question about the comparison of the natural gas price forecast contained in the 2015 IRP to OG&E’s contract prices, OG&E responded that as with coal prices they do not update gas forecasts based on short term market changes.

OG&E’s presentation then transitioned to quantitative analyses and results. OG&E identified the five environmental compliance plans that were analyzed in the 2014 IRP Update (combinations of scrub, convert, and replace) under three market scenarios – base case, high conversion and low conversion of SPP coal-fired generation resources.³ OG&E described the impact of each of the three customer cost components on the total 30-year net present value of customer costs (“NPVCC”). OG&E described that the results indicated that: i) the scrub/convert option had the lowest 30-yr NPVCC; ii) the scrub alternative had the lowest 30-yr NPVCC in the high conversion scenario but more

³ The base case assumed 4,900 MW of coal to gas conversion; the high conversion case assumed a total of 9,800 MW of coal to gas conversions versus the base case; the low conversion case assumed a total of 2,200 MW of coal to gas conversions.

expensive in the low conversion scenario; iii) the convert alternative had the lowest 30-yr NPVCC in the low conversion scenario but was more expensive in the high conversion scenario.

Next, OG&E presented the results of six sensitivity analyses that each varied one of four assumptions: two natural gas sensitivities (high and low), a carbon price sensitivity (the Base Case did not assume a carbon price), two environmental compliance plan capital cost cases (high and low), and a low SPP load growth forecast. In response to several questions about the Clean Power Plan (“CPP”), OG&E clarified that the scenario assumes a carbon tax of \$15/ton which represents the breakeven operating cost between scrubbed coal units and natural gas combined cycle units. In addition, the analysis does not show if OG&E meets CPP goals since it is unknown how the State of Oklahoma will ultimately comply with its goals. Furthermore, in response to questions about the amount of additional wind resources assumed in the base case, OG&E clarified that they have not included additional wind resources beyond the amount contained in the 2014 IRP Update beyond the SPP wind capacity adjustments.

OG&E’s presentation then examined three specific issues: i) retirement and replacement of the capacity provided by Mustang; ii) the evaluation of the RFI issued by OG&E indicated in the 2014 IRP Update Action Plan; and iii) OG&E’s evaluation of the CPP. OG&E stated that the Mustang Modernization Plan detailed in the 2014 IRP Update remains the same. The existing Mustang units will retire by 2018. The cost of the new combustion turbines at Mustang are lower than the initial estimates based on a competitive bid process. OG&E committed to following up on the status of executed contracts to date for the turbines, including execution dates and contract terms.

In terms of the RFI process, OG&E explained that an RFI was issued for wind resources, solar resources, and a capacity bridge for a PPA from 2020 through 2022 to assess the cost of these options for additional capacity. OG&E described that they sought PPA’s only and not the purchase of assets. They also stated a preference for projects in Oklahoma but are still assessing how to factor this into the analysis. OG&E described the options presented in the RFI as follows: i) the provider assumes 100% of the congestion risk; ii) OG&E accepts 100% of the congestion risk; and iii) a mix of assumption of risk. OG&E indicated that they are still in the process of assessing the responses received.

In terms of the CPP, OG&E stated that the final CPP calls for a mass-based 24% reduction in carbon dioxide emissions by 2030. OG&E’s plan is estimated to reduce OG&E’s carbon emission tonnage by more than 30% by 2020 and 40% in 2030. In response to a question about regional approaches to compliance with the CPP, OG&E stated that they believe that a state approach is best but that they are still reviewing this issue.

OG&E’s last slide of the presentation focused on the Action Plan. OG&E stated its commitment to the pursuit of DR resources and strategies to meet environmental compliance mandates.

Part II: Stakeholder Feedback

Stakeholders provided feedback in several areas. OG&E responses are also presented if they were offered.

1. Environmental Compliance/Clean Power Plan

- Question as to the consideration of the CPP in the 2015 IRP
 - *OG&E indicated that it is premature to add too much language on the CPP in the IRP at this point*
- Question as to whether there have been changes in the operating cost assumptions for the scrubber?
 - *Improved efficiencies and cost benefits in the 2015 IRP are based on detailed engineering work.*

2. Assumptions

- Question on the change to the load forecast in the 2015 IRP.
 - *OG&E reiterated there were only minor changes to DSM assumptions.*
- Question as to why the forecast for the SmartHours program is flat?
 - *The company has achieved the 20% enrollment goal and has not determined future growth opportunities from this program.*
- Suggestion that DSM be included on pie charts as capacity. Also a suggestion that OG&E also include cost of MW saved through DSM?
 - *OG&E committed to considering this suggestion.*
- Question on OG&E's consideration of Distributed Generation ("DG"), which is being considered across the country. When will OG&E address this in the IRP?
 - *OG&E responded that this has been factored in with sensitivities. Customers being more aggressive with DSM will mean OG&E gets more aggressive.*
- Comment that OG&E's DG tariff discourages people from investing in resources that would shave peak. Why isn't OG&E considering encouraging this?
 - *OG&E responded that this is considered in 2015 IRP. Currently, prices are so low that customers are not as interested in DG measures.*
- Question as to whether customers have been polled on their interest in DG?
 - *OG&E responded that they are considering this.*
- Question about whether OG&E has considered load growth within the current economic environment ("can't imagine load growth in current environment")?
 - *OG&E has considered modest load growth of approximately 1%.*

- Suggestion that Louisiana has a short term capacity process that OG&E could consider here.
 - *OG&E committed to considering this.*
- Suggestion that OG&E look at the on-peak economic benefits of New Mexico solar resources and generally solar resources further west.
 - *OG&E committed to considering this.*

3. Wind Energy

- Question as to whether OG&E would provide a specific timeline on when the company will seize the opportunity to use more wind capacity. Why isn't OG&E committing to processes to make sure that costs are as low as they can be? Can you lower costs instead of doing what is on the table?
 - *OG&E responded that they have done an RFI and have looked at the market in response to customer feedback. OG&E is not going to react until the company gets all of the information needed.*

4. IRP Approach

- There was a concern expressed that the IRP captures status quo. There is no projection of vision and no new wind included, no new solar in contrast to other IRPs that add concrete goals on these resources.

5. Rate Impacts

- A suggestion was offered that it would be helpful to have an exhibit on the IRP's rate impact of various customers. OG&E should be sensitive to rate impacts and have a plan to try to reduce rate impacts. OG&E's action plan should drive resource costs down.
- A suggestion was offered that OG&E must be price/rate impact conscious and that it would be helpful to have more information on RFI results.
- Question as to whether information from the RFI can be given to the Commission so that they have access to the information?
 - *OG&E responded that they will take this into consideration.*
- Suggestion that stakeholders would like more information on the costs associated with SPP projects and OG&E allocation of these costs.

IRP Technical Conf

August 25, 2015

| <u>Name</u> | <u>Company</u> |
|-----------------------|-------------------------|
| Bob Vandewater | PUD/OCC |
| Laurie Williams | Sierra Club |
| al armendariz | Sierra Club |
| Eddie Terrill | OK DEQ |
| Deborah Thompson | OK Energy Firm |
| Cheryl Vaught | Vaught & Connor, PLLC |
| Jan Walker Ratliff | Phillips 66 |
| Kendall Parrish | Ron Comingdeer & Assoc. |
| Lundy Riger | AES Shady Point |
| Tom Schroedter | OIEC |
| Scott Norwood | OIEC |
| Mark Garrett | OIEC |
| Nicole King | OCC |
| Joseph Britney | OCC |
| Aaron Pupa | LS Power |
| Chip Clarke (Jack) | Clark, Wood & Patten. |

2015 Integrated Resource Plan

Oklahoma Technical Conference

August 25, 2015

Presentation Outline

- Summary
- Assumptions
- Analysis
- Other Considerations
- Action Plan

OG&E's Environmental Compliance Plan and Mustang Modernization Plan have not changed

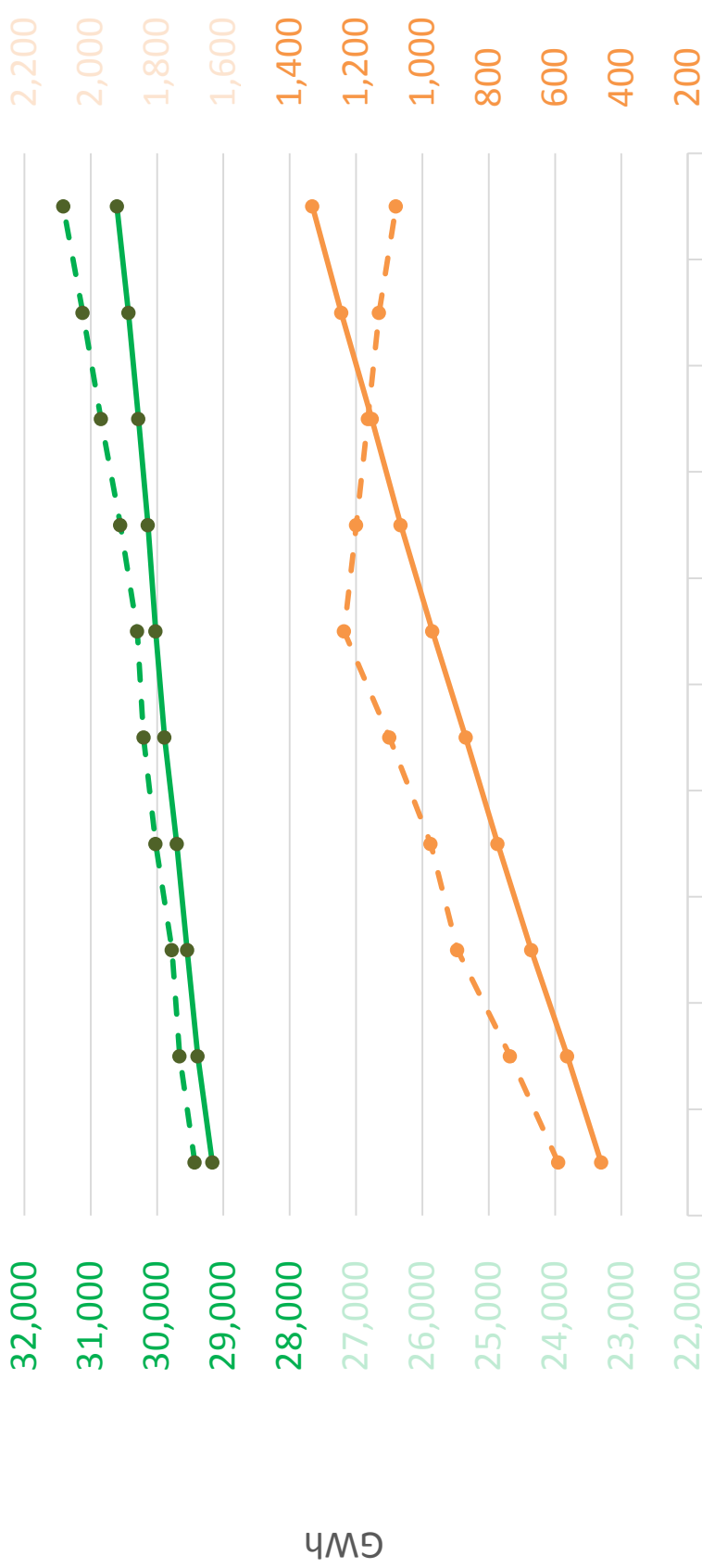
- Environmental Compliance Plan “Scrub/Convert” is the best alternative to comply with Regional Haze and MATS
- Modernizing the Mustang plant by installing new combustion turbines allows OG&E to comply with SPP planning capacity margin while improving system reliability
- The existing Mustang site offers customers the benefits of utilizing existing permits and infrastructure while supporting growth in renewables and distributed generation

Several assumptions were updated from the 2014 IRP Update

- Energy Forecast
- Demand Forecast
- Existing Resources (Capacity)
- Planning Capacity Margin (Capacity Needs)
- Emission Control Technology Costs
- EIA Fuel Forecast

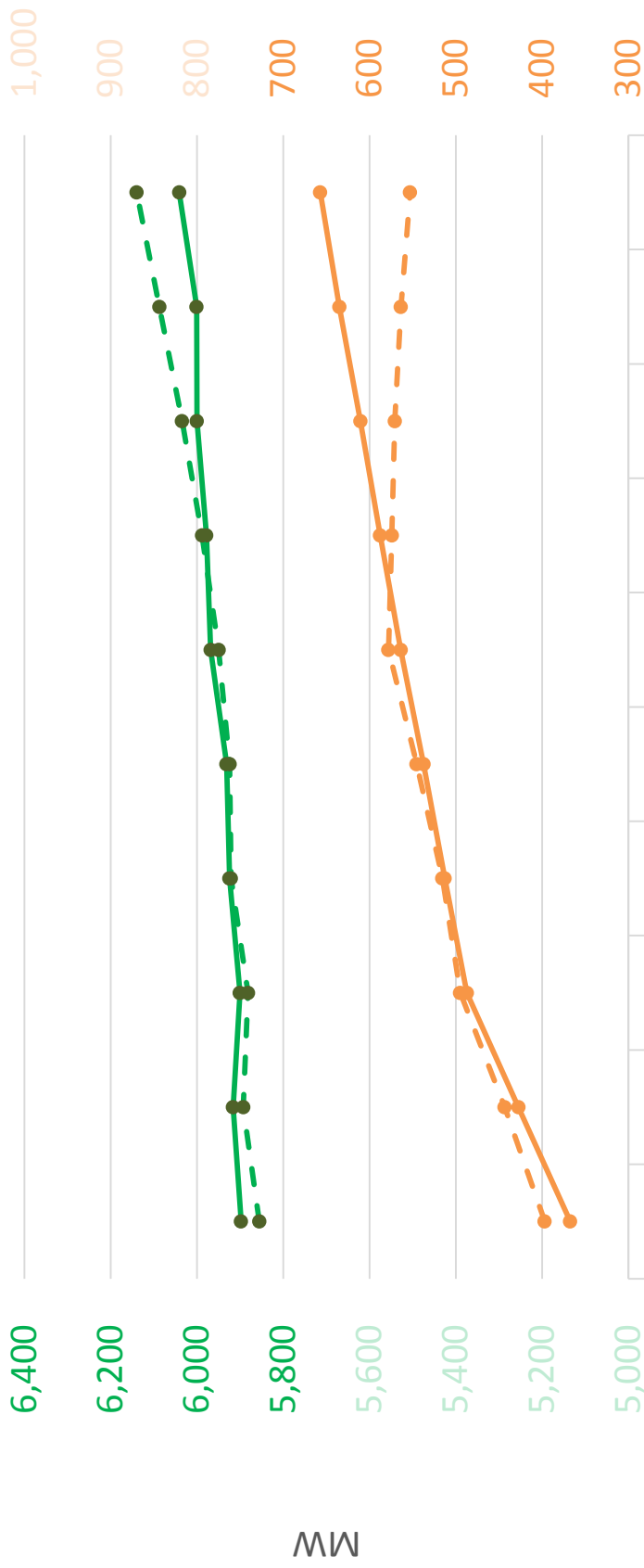
These updates do not have a material impact on the analysis from the 2014 IRP Update so the Action Plan remains the same.

Updated energy forecast is consistent with prior forecasts



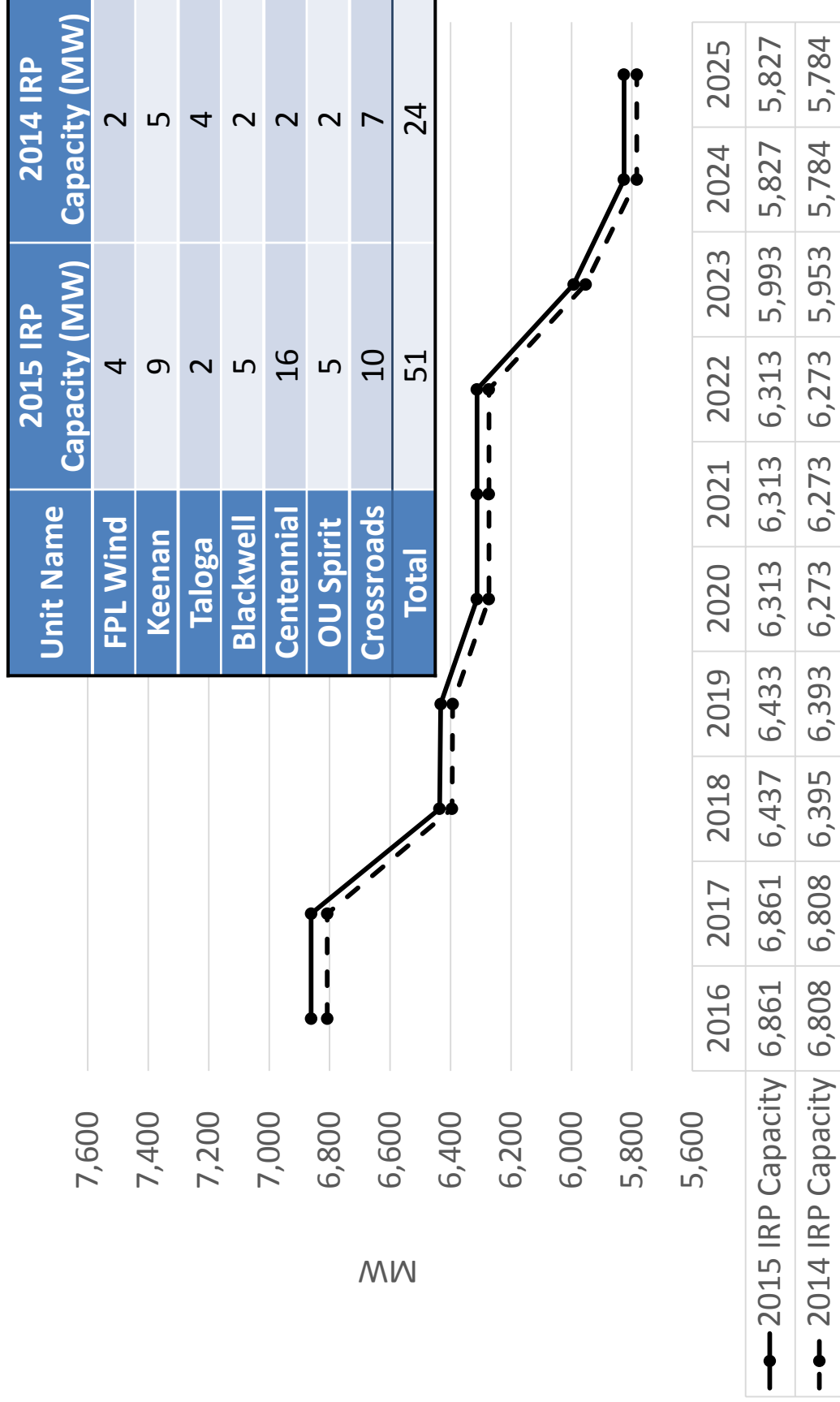
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|--------------------------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| 2015 IRP Energy Forecast | 29,167 | 29,387 | 29,547 | 29,703 | 29,887 | 30,023 | 30,138 | 30,281 | 30,431 | 30,604 |
| 2014 IRP Energy Forecast | 29,433 | 29,661 | 29,777 | 30,023 | 30,204 | 30,298 | 30,554 | 30,847 | 31,121 | 31,414 |
| 2015 IRP DSM | 461 | 563 | 672 | 773 | 869 | 970 | 1,065 | 1,153 | 1,244 | 1,332 |
| 2014 IRP DSM | 590 | 736 | 895 | 975 | 1,099 | 1,236 | 1,199 | 1,164 | 1,131 | 1,080 |

Updated demand forecast is consistent with prior forecasts

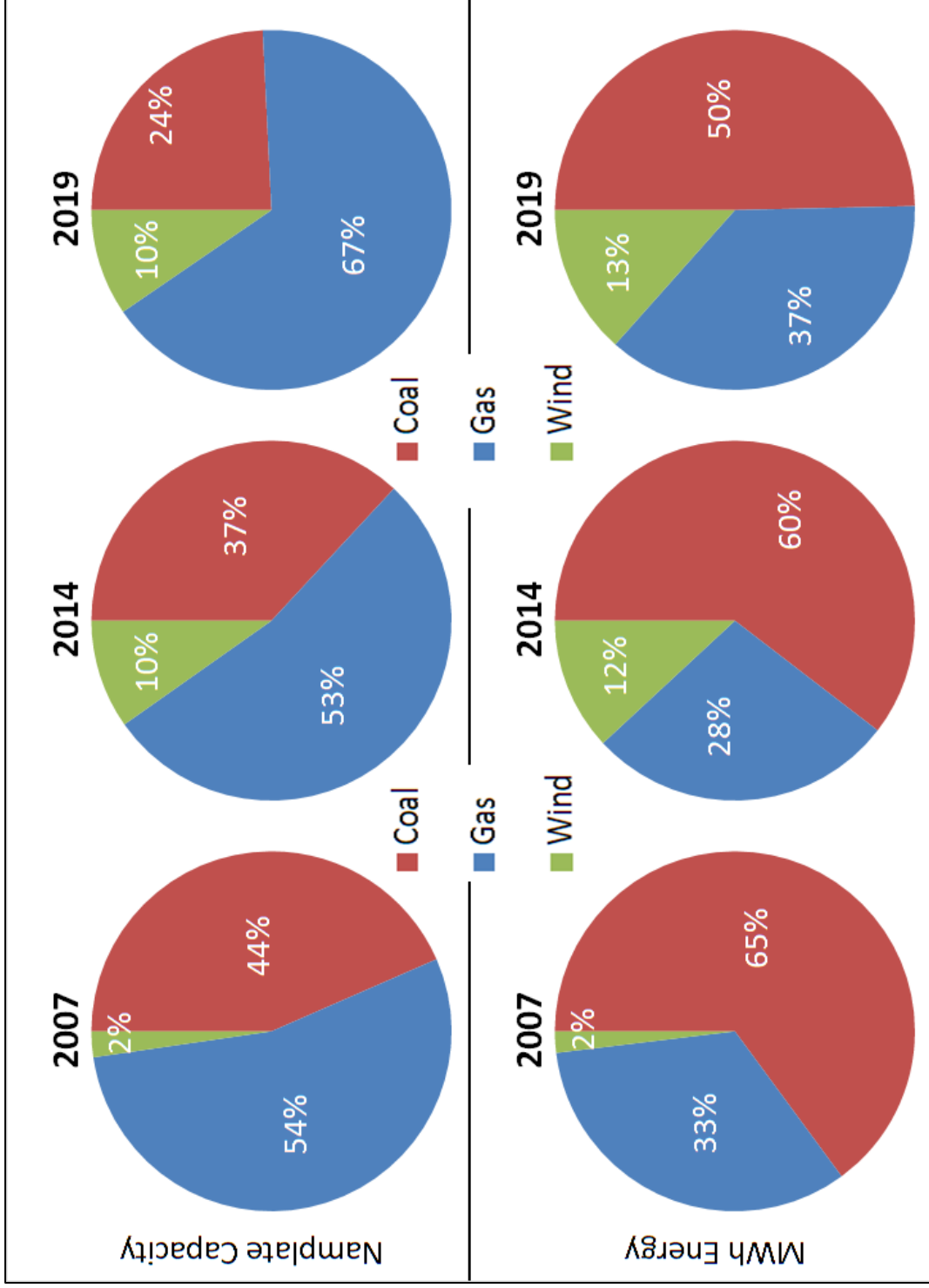


| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|-----------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| 2015 IRP Demand | 5,898 | 5,916 | 5,900 | 5,924 | 5,931 | 5,968 | 5,978 | 6,000 | 6,001 | 6,041 |
| 2014 IRP Demand | 5,855 | 5,892 | 5,882 | 5,921 | 5,924 | 5,950 | 5,988 | 6,034 | 6,087 | 6,140 |
| 2015 IRP DSM | 367 | 427 | 487 | 513 | 537 | 564 | 588 | 611 | 635 | 657 |
| 2014 IRP DSM | 397 | 443 | 495 | 515 | 545 | 578 | 574 | 571 | 564 | 553 |

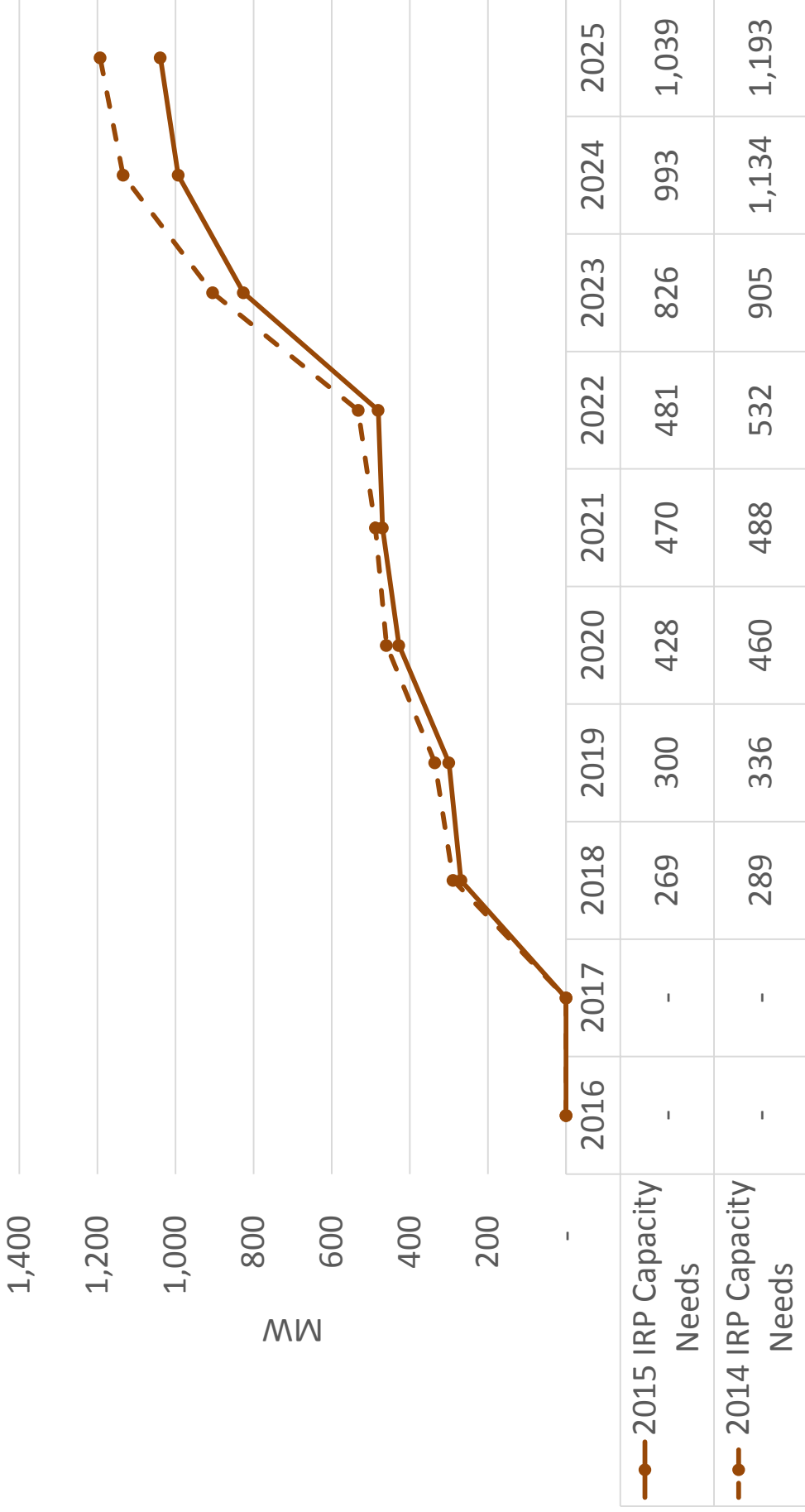
2015 IRP Unit Capacities were updated to include the newest SPP criteria for Wind Capacity



OG&E is gradually shifting generation resources while maintaining fuel diversity



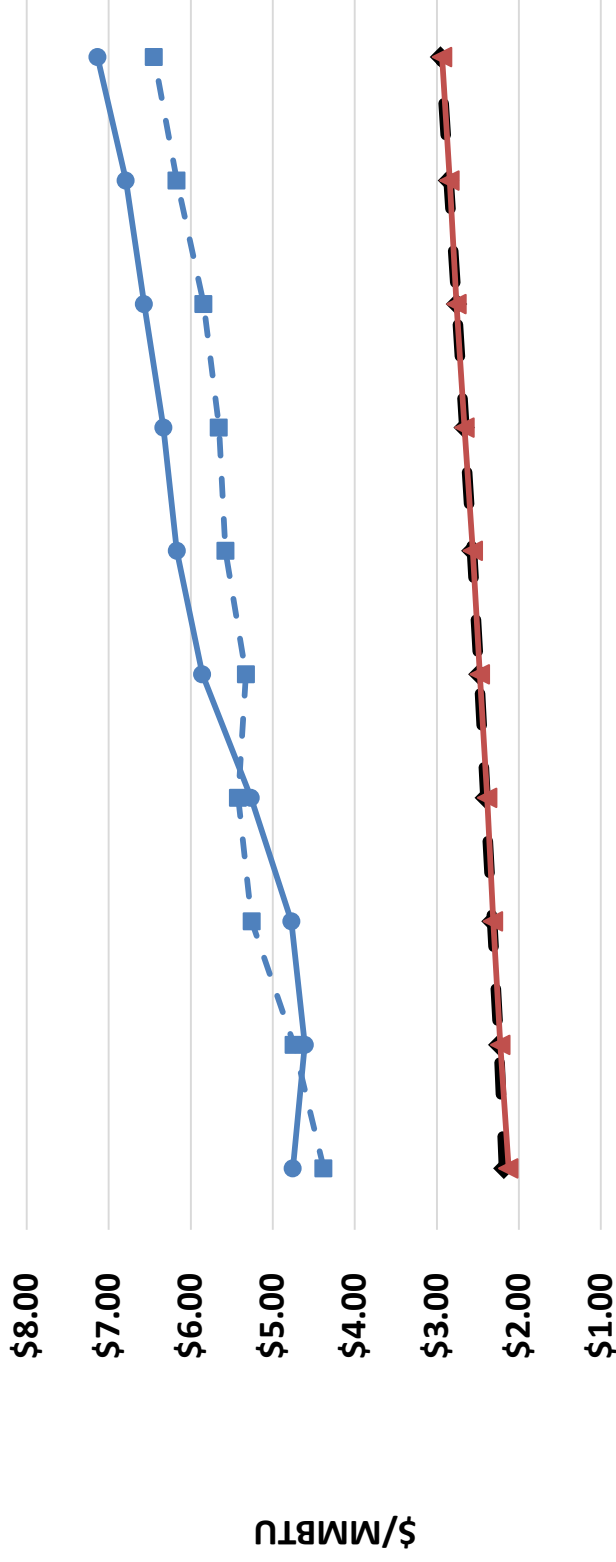
OG&E has capacity needs in 2018 with the retirement of the existing Mustang Units



Emission control technology cost assumptions have been updated to show recent estimates

| Control | Units | 2015 IRP (\$Millions) | 2014 IRP (\$Millions) | Increase/ (Decrease) (\$Millions) |
|-----------------------------|-------------------|--------------------------|--------------------------|---|
| Dry Scrubber | All Coal per unit | \$245.0 | \$247.9 | (\$2.9) |
| Low NO _x Burners | Muskogee 4 | \$9.3 | \$11.0 | (\$1.7) |
| Low NO _x Burners | Sooner 1 | \$11.9 | \$10.6 | \$1.3 |
| Low NO _x Burners | Seminole 1&2 | \$43.1 | \$41.3 | \$1.8 |
| Low NO _x Burners | Seminole 3 | \$19.6 | \$19.0 | \$0.6 |
| Activated Carbon Injection | All Coal | \$22.7 | \$24.3 | (\$1.6) |
| Conversion to Gas | Muskogee per unit | \$38.0 | \$35.7 | \$2.3 |
| Conversion to Gas | Sooner per unit | \$38.0 | \$35.7 | \$2.3 |

2015 EIA forecast projects gradual increases for coal and natural gas prices over the next decade



| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|--------------------------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
| —■— Natural Gas AEO 2014 | \$4.38 | \$4.74 | \$5.26 | \$5.42 | \$5.33 | \$5.58 | \$5.66 | \$5.84 | \$6.17 | \$6.45 |
| —●— Natural Gas AEO 2015 | \$4.76 | \$4.61 | \$4.77 | \$5.27 | \$5.86 | \$6.17 | \$6.33 | \$6.57 | \$6.79 | \$7.14 |
| —▲— Coal AEO 2014 | \$2.18 | \$2.24 | \$2.33 | \$2.41 | \$2.49 | \$2.57 | \$2.66 | \$2.76 | \$2.85 | \$2.95 |
| —▲— Coal AEO 2015 | \$2.13 | \$2.22 | \$2.31 | \$2.39 | \$2.47 | \$2.56 | \$2.66 | \$2.76 | \$2.84 | \$2.93 |

2014 IRP Update evaluated five alternative Regional Haze environmental compliance plans

Scrub/Convert

- Scrub Sooner 1 by 2018 and Sooner 2 by 2019
- Convert two Muskogee units by 2019

Scrub

- Scrub Muskogee 4 by 2018 and Muskogee 5 by 2019
- Scrub Sooner 1 by 2018 and Sooner 2 by 2019

Convert

- Convert four coal units to gas by 2019

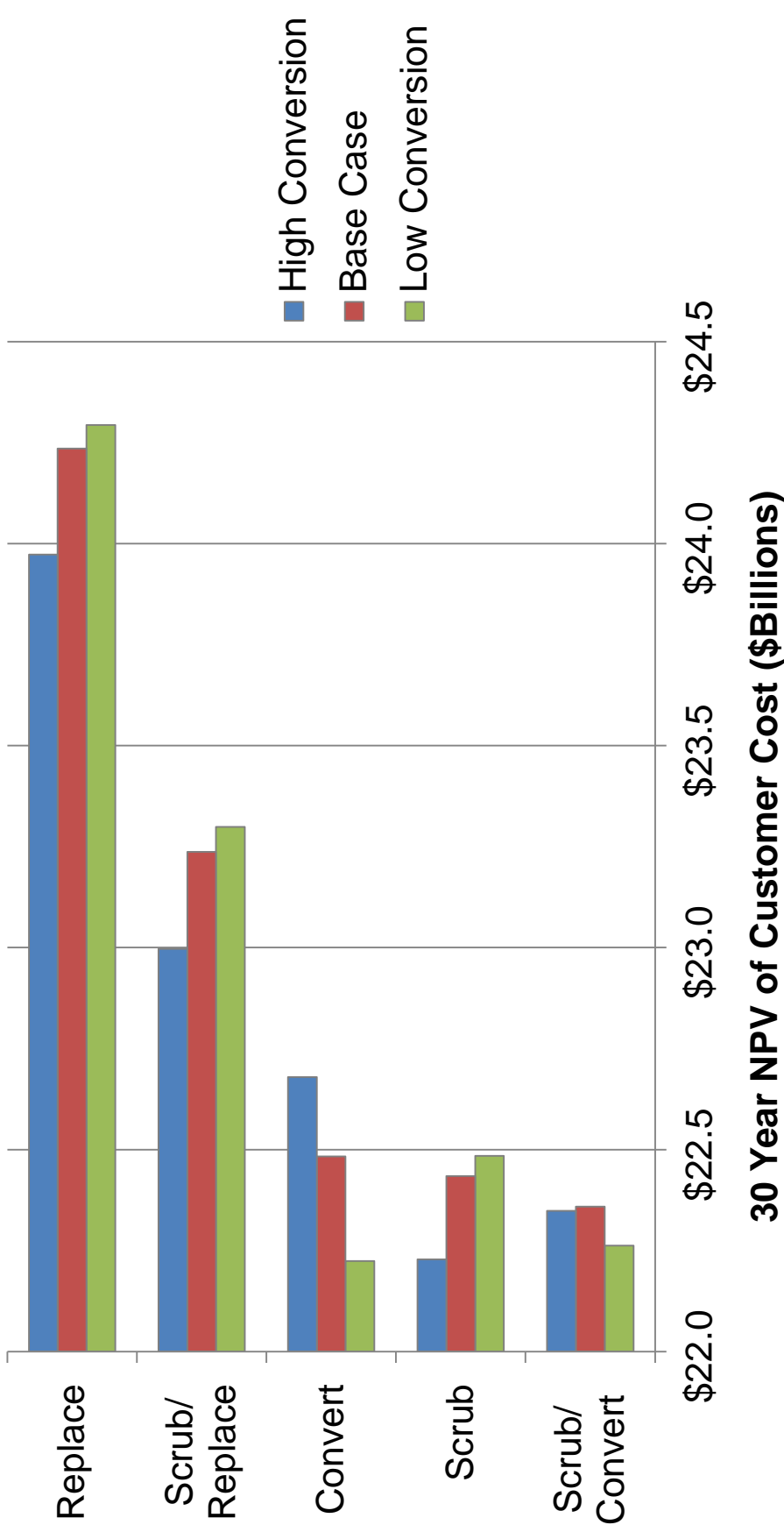
Scrub/Replace

- Scrub Sooner 1 by 2018 and Sooner 2 by 2019
- Replace two Muskogee coal units with new CCs by 2019

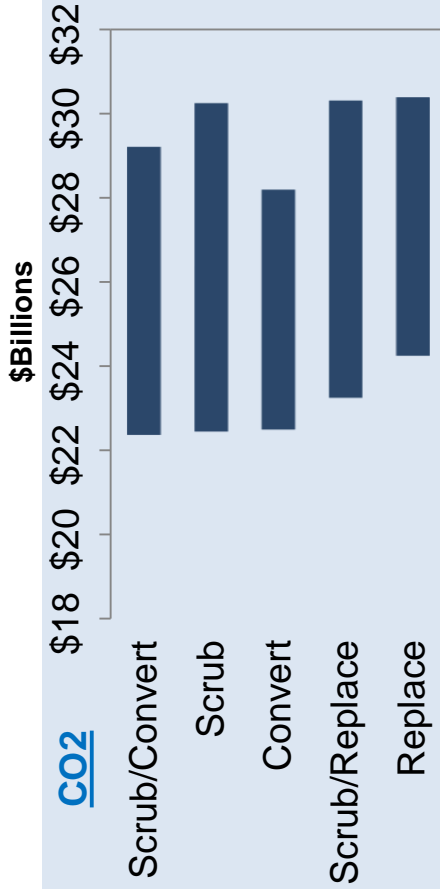
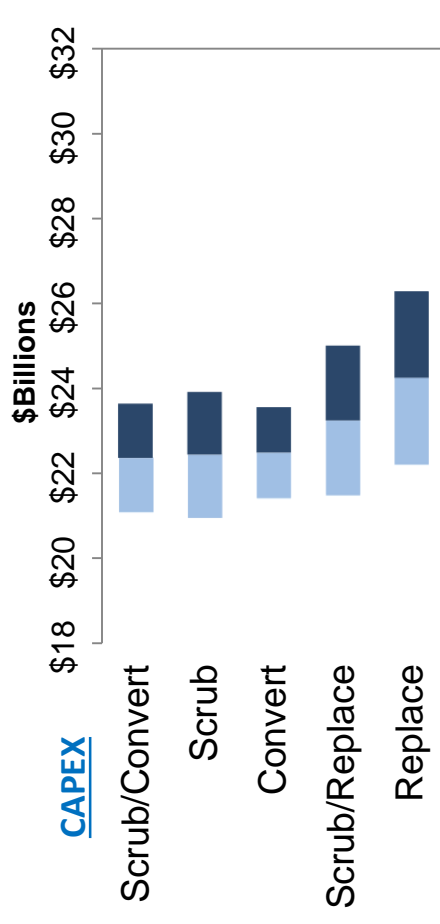
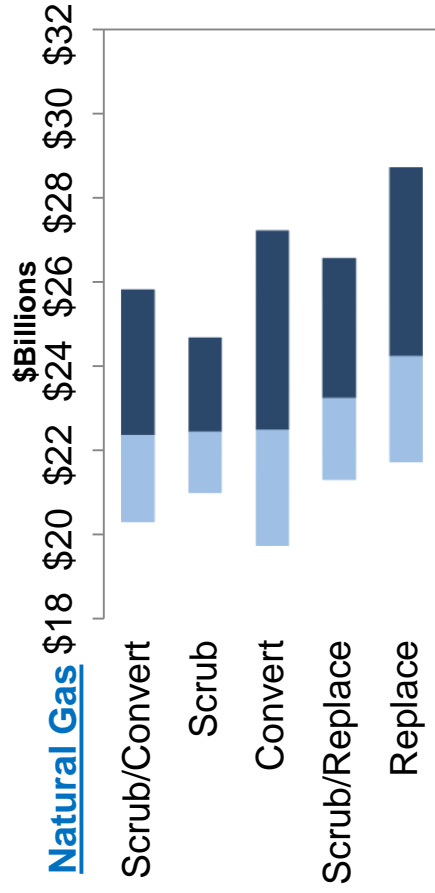
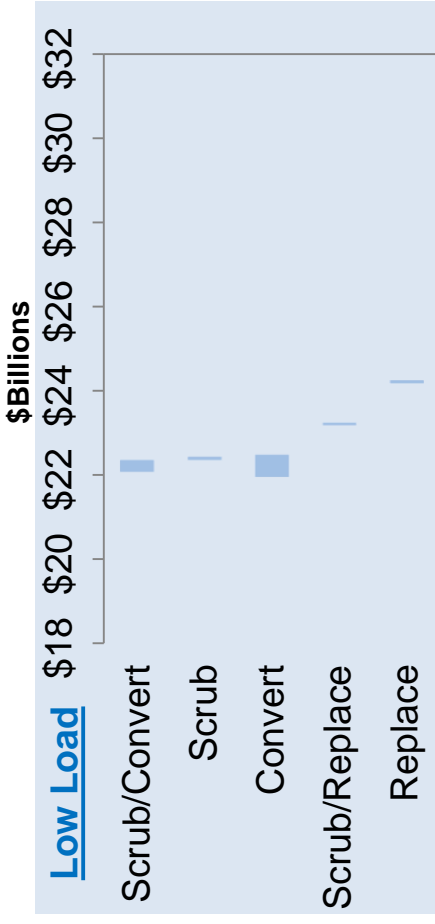
Replace

- Replace four coal units with new CCs by 2019

Performance of alternatives was considered in each market scenario for the 2014 IRP Update



Sensitivity analysis in the 2014 IRP Update projects risk of individual assumptions



Mustang Modernization Plan remains the same

- **Existing Mustang units will retire by 2018**

- Unit ages: 58 to 67 years with often non-existent replacement parts
- Greater risk of catastrophic failure and creates a greater safety risk for employees

- **Costs of new combustion turbines at Mustang are lower than initial estimates**

- Seven 57 MW combustion turbines were purchased under contracts that were competitively bid
 - Lower than original cost estimates
 - Improved operating characteristics and variable O&M cost
- Installations packages and balance of plant equipment will also be purchased under a number of competitively awarded contracts as sufficient engineering is completed to support these bid events.

OG&E is currently evaluating responses to the RFI indicated in the 2014 IRP Update Action Plan

- Wind
 - Must include option to accept all congestion risk
 - Responses from 14 companies
 - 21 locations offered
 - Oklahoma, Texas and Kansas
- Solar
 - Responses from 14 companies
 - 25 locations offered
 - Oklahoma, Texas and New Mexico
 - Gaining experience from 2.5 MW of central solar energized in 2015 at Mustang
- Capacity Bridge – 2020-2022 PPA
 - Responses from 4 companies

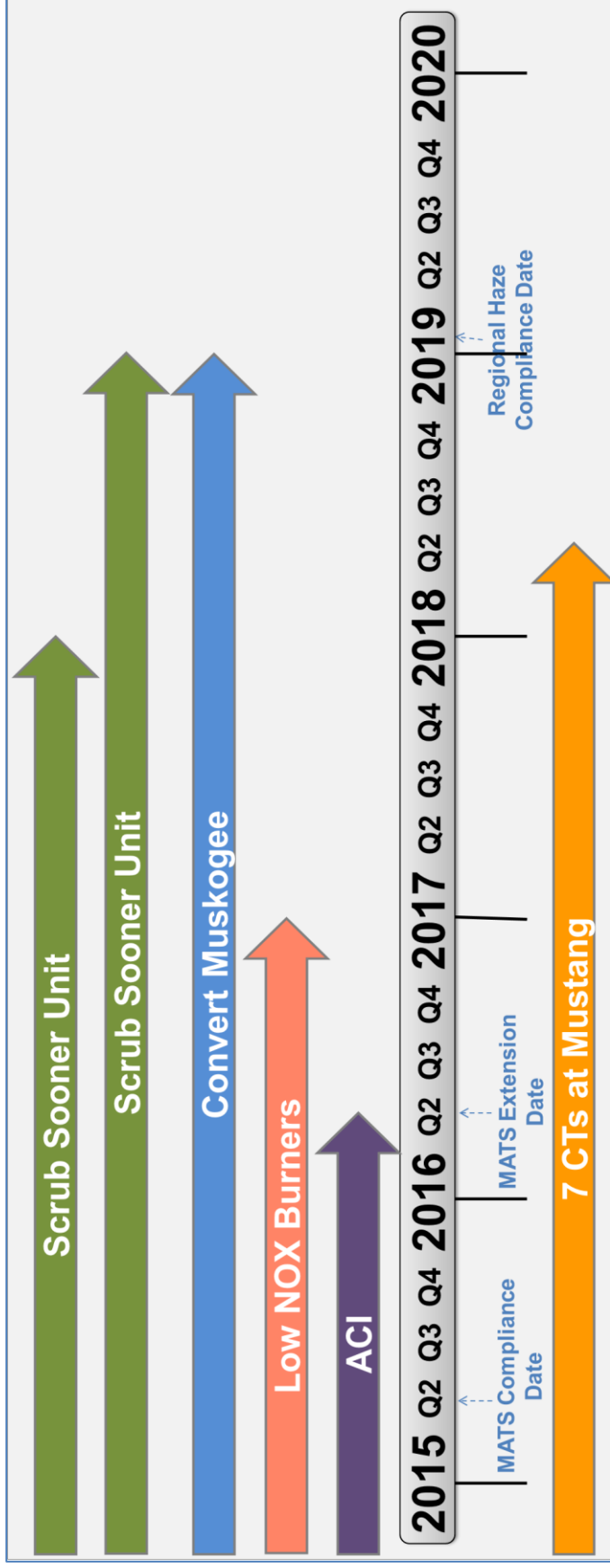


OG&E is currently evaluating EPA's Clean Power Plan (CPP)

- The CPP calls for a 24% reduction in CO₂ tons in Oklahoma by 2030
- OG&E's plan is estimated to reduce OG&E's CO₂ emission tonnage by more than 30% by 2020 and 40% in 2030
- Combined with the coal unit retirements by PSO and GRDA, OG&E's environmental compliance plan positions Oklahoma well to address the requirements of the rule

OG&E's 5 year Action Plan includes emission control technologies and new CTs at Mustang

The MATS rule currently remains in effect and OG&E is still required to meet the April 2016 compliance deadline



Regional Haze compliance date is set 55 months from US Supreme Court decision.
 Clock restarted 5/29/2014 + 55 months = 1/4/2019

**POSITIVE
ENERGY
TOGETHER®**

Feedback

WITH ALL YOUR POWER  WHAT WOULD YOU DO?