BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR COMMISSION AUTHORIZATION OF A PLAN TO COMPLY WITH THE FEDERAL CLEAN AIR ACT AND COST RECOVERY; AND FOR APPROVAL OF THE MUSTANG MODERNIZATION AND COST RECOVERY	))))))))	CAUSE NO. PUD 201400229

REDACTED

Direct Testimony

of

Robert J. Burch

on behalf of

Oklahoma Gas and Electric Company

August 6, 2014

Q. **Would you please state your name and business address?**

A. My name is Robert J. Burch. My business address is 321 North Harvey, Oklahoma City, Oklahoma 73102.

Q. **By whom are you employed and in what capacity?**

A. I am employed by Oklahoma Gas and Electric Company ("OG&E" or "Company") as Director, Power Supply Services. I began my career with OG&E in 2012.

Q. **Would you please summarize your professional and educational background?**

A. I have been employed by four electric utility companies, a specialty chemicals refinery and a nationwide food manufacturing company over the last 29 years in a number of positions of responsibility including engineering, maintenance and operations encompassing various management and executive assignments. Most recently, I was employed by Duke Energy/Cinergy in several positions, the last of which was Director of Engineering, Edwardsport IGCC generation station. The Edwardsport IGCC generation station is a $3.6 billion state of the art, advanced coal facility that entered commercial operation in 2013. My duties on the project included leading the effort to obtain all of the required environmental permits, technical management of 27 engineers engaged in the review of the plant engineering design, including a $130 million zero liquid discharge system to treat process wastewater and project management responsibilities for an 8 mile, $32 million private rail spur into the facility.

I received a Bachelor's of Science degree in Mechanical Engineering in 1985 from Rose-Hulman Institute of Technology.

Q. **Have you previously testified before the Corporation Commission of Oklahoma?**

A. No.

Q. **Have you previously testified before any other jurisdictions?**

A. Yes. I have testified before the Indiana Utility Regulatory Commission related to the construction of Duke Energy's Integrated Gasification Combined Cycle ("IGCC") Plant at Edwardsport, Indiana.

Q. **What is the purpose of your testimony in this cause?**

A. My testimony provides an overview of the OG&E generating facilities that are affected by the Regional Haze Rule ("RHR"), including the State Implementation Plan ("SIP") and the Federal Implementation Plan ("FIP"), and the Mercury and Air Toxics Standards ("MATS") Rule. I then explain how OG&E explored various technological options for complying with the emission limits imposed on the Company through the Regional Haze and MATS Rules and how the Company evaluated these options based on effectiveness, cost and timing. I summarize the OG&E plan resulting from our evaluation and will also provide an overview of the engineering, permitting, design and construction process and how OG&E is taking steps to ensure that the selected plan would be implemented at the lowest reasonable cost. Also, I explain OG&E's decision to replace its four units at the Mustang generating facility with modern combustion turbines ("CTs").

I. OVERVIEW OF THE OG&E GENERATING UNITS AFFECTED BY REGIONAL HAZE AND MATS

Q. **Which OG&E generation facilities are affected by MATS Rule and the Regional Haze Rule?**

A. The MATS Rule is designed to reduce emissions of mercury ("HG"), Particulate Matter ("PM") and Hydrogen Chloride ("HCL" or "acid gases") from coal fired electric generating plans and affects all five of OG&E's coal-fired generating units (both Sooner Units and all three Muskogee Units). The RHR is intended to improve visibility in national parks and wilderness areas to natural conditions by 2064 and targets emissions of sulfur dioxide ("SO_2") and nitrogen oxide ("NO_X"). The RHR affects four OG&E coal-fired generating units (Sooner Units 1 and 2 and Muskogee Units 4 and 5) and three gas-fired generating units (Seminole Units 1, 2 and 3). Muskogee Unit 6 was not in

existence prior to August 1977, and therefore it is not affected by the RHR. OG&E Witness Usha Turner provides greater details on these two rules.

Q. **What portion of OG&E's total generating capacity do the facilities affected by the RHR and MATS Rules represent?**

A. OG&E owns approximately 6,336 megawatt ("MW") of fossil fuel generating capacity (not including capacity purchases from AES Shady Point and PowerSmith). The OG&E generation facilities affected by the RHR and/or MATS Rules total approximately 4,000 MW. This equates to 63% of OG&E's total owned fossil fuel generating capacity and approximately 52% of total 2013 megawatt hours ("MWh") generated.

Q. **Please describe the affected OG&E generating stations.**

A. The Sooner generating station is located near Red Rock, Oklahoma. It includes two steam electric generating units of nominally 500 MW each that are designated as Sooner Units 1 and 2. Both units fire sub-bituminous (low sulfur) coal as their primary fuel. Sooner Unit 1 became operational in 1979 and Sooner Unit 2 became operational in 1980. Coal supply for these units is obtained from mines in the Powder River Basin ("PRB") area of Wyoming which is the cleanest coal available from a sulfur content perspective.

The Muskogee Generating Station is located near Muskogee, Oklahoma. It includes three steam electric generating units designated as Muskogee Units 4, 5 and 6. The rated capacity for each of the Muskogee Units is nominally 500 MW. All three Muskogee Units fire sub-bituminous coal as their primary fuel. Muskogee Units 4 and 5 became operational in 1977 and 1978, respectively and Muskogee Unit 6 became operational in 1984. Coal supply for these units is the same as supplied to the Sooner units.

The Seminole generating station is located northeast of Konawa, Oklahoma. It has three steam electric generating units that are designated as Seminole Units 1, 2 and 3. Each of the Seminole Units has a nominal rated capacity of 500 MW. Seminole Units 1 and 2 became operational in 1971 and 1972, respectively, and Seminole Unit 3 became operational in 1975. All three units utilize natural gas as their fuel.

Q. **What are the emission limits contained in the RHR and what is the timeline for meeting those requirements?**

A. As described by OG&E Witness Turner, the Regional Haze Rule requires OG&E to meet certain emission limits for both SO_2 and NO_X utilizing the Best Available Retrofit Technology ("BART").[1] BART is the best available emission control technology for existing units as determined by an engineering study that weighs the five factors discussed by Witness Turner. With regard to the BART for controlling NO_X emissions, OG&E, under the Regional Haze SIP that was approved by the EPA, is installing low NO_X burners ("LNB") and over-fired air systems ("OFA") on its seven Regional Haze affected generation units (and flue gas recirculation ("FGR") on the affected gas plants). The Regional Haze NO_X compliance date is January 27, 2017.

While the EPA accepted Oklahoma's BART determination for NO_X in the final rule, it rejected Oklahoma's SO_2 BART determination with respect to the four affected coal-fired units. The EPA instead issued its FIP requiring that OG&E meet an SO_2 emission rate of 0.06 lbs/MMBtu within a five year (60 month) period.

Approximately five months had elapsed on the FIP compliance timeline before the 10th Circuit granted a stay of the FIP on June 22, 2012. When the United States Supreme Court denied OG&E's appeal on May 27, 2014, the compliance timeline resumed on May 30, 2014 and OG&E has until January 4, 2019 to comply with the FIP SO_2 emission requirements.

Q. **What are the emission limits contained in the MATS Rule and what is the timeline for meeting those requirements?**

A. The MATS Rule requires OG&E to meet emission limits for mercury, PM and HCL at all of the Company's coal fired electric generating units. The MATS Rule was finalized on April 16, 2012 and requires affected units to be in compliance within three years from this date. A one year extension was granted to OG&E, which makes April 16, 2016 the

[1] As noted by OG&E Witness Turner, the Oklahoma Regional Haze SIP also contained BART determinations related to PM emissions at OG&E's Sooner Units 1 and 2 and Muskogee Units 4 and 5. Those BART determinations concluded that OG&E should continue to use the existing electrostatic precipitators at those units to control PM emissions to the levels contained in the SIP. The portion of the Oklahoma SIP containing these BART determinations was approved by the EPA.

compliance date for meeting the MATS Rule. The requirements for this rule and its specific limits will be addressed by OG&E Witness Turner.

II. TECHNOLOGICAL OPTIONS

A. TECHNOLOGICAL OPTIONS FOR MEETING NO_X REQUIREMENTS OF REGIONAL HAZE

Q. **Please explain the technological controls for complying with the NO_X emission limits required by the Regional Haze SIP.**

A. The Regional Haze SIP identified the combustion controls option of LNB/OFA (and FGR for gas units) as the BART for the seven affected OG&E units. LNB/OFA and FGR limit NO_X formation by controlling the combustion process and internal boiler flame temperatures. OFA allows for staged combustion to occur in multiple areas of the boiler with a cooler flame in the initial stage and less oxygen in the second stage. FGR recycles a portion of the flue gas back into the primary combustion zone. The staged combustion along with FGR controls the flame temperature which in turn controls NO_X formation.

Q. **What are some of the other technological control options that OG&E considered during its BART determination for meeting the NO_X emission limits?**

A. In developing its recommendation to the Oklahoma Department of Environmental Quality ("ODEQ") when the agency was developing its Oklahoma SIP, OG&E considered both Selective Non-Catalytic Reduction ("SNCR") and Selective Catalytic Reduction ("SCR") technologies for post combustion NO_X control. Normally, SNCRs and SCRs function in concert with LNB systems.

SNCR involves the direct injection of ammonia or urea after the combustion zone but at a point in the boiler where flue gas temperatures remain relatively high. The reaction of the ammonia or urea and the products of combustion reduces the presence of NO_X. During the original BART determination, SNCR's had several unresolved technical difficulties when applied to large gas and coal fired utility boilers (including the physical size of the boiler, inadequate ammonia mixing, and ash characteristics).

Assuming that SNCR could be installed on our large units, NO_X control effectiveness (rate at which a pollutant is emitted after control system has been installed) would be marginal, and depending on boiler exit temperatures, could actually result in additional NO_X formation. Because of SNCR technical problems and limited usage on large utility boilers during the initial BART determination, it was determined that the control technology was not applicable to the OG&E Units. Therefore, SNCR was not evaluated further in the BART analysis.

SCRs involve injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NO_X. Anhydrous or aqueous ammonia injection systems may be used, or ammonia may be generated on-site from a urea feedstock. The effectiveness of the SCR system depends on site-specific considerations including the ammonia injection rate, site-specific flue gas characteristics, ammonia slip, and the condition of the catalyst.

SCR has been installed as a retrofit control technology on both large gas-fired and existing coal-fired boilers, including boilers firing subbituminous coal. This technology was not selected as BART due to its very high NO_X removal cost compared to LNB/OFA.

Q. **Please describe the systems and equipment that are involved in the installation of Low NO_X burners.**

A. Unit modifications related to installation of a LNB/OFA combustion system include installation of ductwork, pressure parts, OFA system dampers and drives as well as new burner components including air tips, fuel tips and associated hardware. Modifications to the windbox, windbox dampers and burner tilt drives are necessary as well as the installation/modification to access platforms for this equipment. Demolition, removal and relocation of interfering components is required to facilitate installation. Lastly, incorporation of new combustion system software into new or existing distributed control systems ("DCS") is necessary to achieve proper control of the new equipment.

Q. **What are the equipment, installation and operating costs for a LNB as compared to a LNB with SCRs?**

A. The capital and operating costs associated with adding an SCR are significant, but provide little to no incremental visibility improvements. As shown in Table 1 for a Sooner unit, the capital investment and operating cost of adding a SCR would result in approximately a 15 times higher total cost than just adding a LNB and the additional annual emission reduction (tons per year or "tpy") from an SCR is marginal.

Table 1: Sooner Unit 1 NO_X Summary

Control Technology	Annual Emission Reduction (tpy)	Total Capital Investment ($)	Revenue Requirement ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)	Average Control Efficiency ($/ton)	Incremental Control Efficiency ($/ton)
LNB/OFA + SCR	10,709	$192,018,500	$16,477,200	$14,487,400	$30,964,600	$2891	$17,905
LNB/OFA	9,096	$14,055,900	$1,206,100	$877,100	$2,083,200	$229	NA

Note: The information in this table is extracted from 2008 BART analysis provided to ODEQ and is also representative of costs on all affected coal units.

Q. **How were these cost estimates developed?**

A. The 2008 cost estimates were developed by Sargent & Lundy ("S&L"), OG&E's consulting engineer, and were based on detailed costs estimates for similar S&L projects. Capital costs were compared to U.S. EPA's Coal Utility Environmental Cost Workbook[2], and updated to account for any recent increases (at the time of the evaluation) in purchased equipment and commodity costs.

Q. **What is the current status of installing LNB/OFA as approved by EPA?**

A. As mentioned above, OG&E is required to install LNB/OFA systems on seven (7) units – 4 coal units and 3 gas units. To date, these systems have been installed on 3 coal units (Sooner Units 1 & 2 and Muskogee Unit 5). The current schedule is to install the

[2] Sixth Edition, January 2002.

remaining four (4) systems during scheduled unit outages occurring between spring of 2015 and January 2017, the Regional Haze NO_X compliance date.

Q. **Can you please describe the approach utilized by OG&E for the procurement of LNB/OFA systems?**

A. The equipment for the LNB/OFA projects was competitively bid. The equipment for all of the affected coal units was in one bid package, with a separate bid package for the Seminole gas units, providing improved pricing for multiple units of common equipment.

Q. **How do the current forecast of expenditures compare with original estimates developed as part of BART evaluations?**

A. The current forecast of total expenditures for procurement and installation of all the LNB/OFA projects related to Regional Haze is approximately $99.4 million, as compared to the 2008 BART estimate of $100 million.

B. TECHNOLOGICAL OPTIONS FOR MEETING SO_2 REQUIREMENTS OF REGIONAL HAZE

Q. **What are the technological options for complying with the SO_2 emission limits required in the Regional Haze FIP?**

A. The Regional Haze FIP for the State of Oklahoma gave a compliance limit of 0.06 lbs/MMBtu of SO_2 for each of the affected coal units ("SO_2 Targets"). The technological control options to comply with these limits can be classified into pre-combustion and post-combustion options. Potentially feasible pre-combustion control strategies designed to reduce overall SO_2 emissions consist of coal switching, coal washing and coal processing. Over the past few decades, post-combustion flue gas desulfurization ("FGD") has been the most commonly used SO_2 control technology for large pulverized coal-fired utility boilers such as OG&E's affected coal units. FGD technologies generally fall into two categories, Wet-FGD ("Wet Scrubber" or "Wet Scrubbing") and Dry-FGD ("Dry Scrubber" or "Dry Scrubbing") systems.

Q. **Please describe the various pre-combustion technological control options reviewed by OG&E.**

A. The various pre-combustion options for reducing SO_2 consist of coal switching, coal washing and coal processing. Several coal fired utilities have switched to low sulfur coal as an SO_2 emission control strategy because SO_2 emissions are directly related to the sulfur content in coal. OG&E has always burned low sulfur coal at its existing coal plants and is presently burning among the lowest sulfur coal available at its coal plants. Switching to alternative coals (bituminous coal or lignite) will not reduce potential uncontrolled SO_2 emissions or controlled SO_2 emissions. Therefore, switching to a different coal is not considered a feasible option for compliance.

Coal washing is used to reduce impurities in the coal such as ash and sulfur. In general, coal washing is accomplished by separating and removing inorganic impurities from organic coal particles. Coal washing has typically been used at plants that fire bituminous coal since the main impurity that it reduces is sulfur. According to S&L, coal washing has become an obsolete practice in the industry. Therefore, coal washing is not considered an available retrofit control option for OG&E's coal units.

Coal processing technologies were being developed to remove potential contaminants from the coal prior to use. To date, the use of processed fuels has only been demonstrated with test burns in a pulverized coal-fired boiler. At the time of BART analysis, no coal-fired boilers have utilized processed fuels as their primary fuel source on an on-going, long-term basis. Therefore, the option of coal processing is not considered commercially viable.

Q. **Please describe some of the various scrubber technology designs and how they work.**

A. Wet Scrubbing technology is an established SO_2 control technology. Wet Scrubbing systems vary in design. However, all Wet Scrubbing systems utilize an alkaline scrubber slurry reacting with the flue gas to remove SO_2. Although the flue gas/reactant contact systems may vary with vendor specific designs, the chemistry involved in all Wet Scrubbing systems is essentially identical.

Dry Scrubbing, is another scrubbing system that has been designed to remove SO_2 from coal-fired combustion gases. Dry Scrubbing involves the introduction of dry or

hydrated lime slurry into a reaction tower where it reacts with SO_2 in the flue gas to form calcium sulfite solids. Unlike Wet Scrubbing systems that produce a wet slurry byproduct that is collected separately from the fly ash, Dry FGD Scrubber systems produce a dry byproduct that must be removed with the fly ash in the particulate control equipment. Dry FGD Scrubber systems vary in design but are typically classified as spray dryer absorber ("SDA"), dry sorbent injection ("DSI"), and circulating dry scrubber ("CDS").

Q. **Did OG&E evaluate different post-combustion technologies?**

A. Yes. OG&E evaluated different post-combustion technologies several times over the past six years. The first evaluation occurred when OG&E was required to perform a BART analysis under the Regional Haze Rule. This analysis was performed by S&L for OG&E in 2008. The BART analysis includes a review of available retrofit control technologies including various types of Wet and Dry FGD technologies. A comparison of costs and annual emissions from Wet and Dry FGDs, taken from the original BART determination for a Sooner unit, are shown in Table 2, below. Regarding Wet FGD technologies, it was concluded that in addition to the economic impacts, there were several collateral environmental impacts including greater particulate emissions, significantly higher make up water requirements than dry systems and the generation of a wastewater stream that must be treated and discharged under a separate new environmental discharge permit. OG&E concluded that due to the above collateral impacts listed and lower cost to construct and operate, that Dry FGD represented a lower cost impact to our customers.

Table 2: Sooner Unit 1 SO_2 Summary

Control Technology	Annual Emission Reduction (tpy)	Total Capital Investment ($)	Revenue Requirement ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)	Average Control Efficiency ($/ton)	Incremental Control Efficiency ($/ton)
WFGD	15,731	$441,658,000	$37,898,900	$42,998,900	$80,897,800	$5143	$18,255
DFGD=SDA	15,327	$390,406,000	$33,500,900	$40,021,700	$73,522,600	$4797	NA

Note: The information in this table is extracted from 2008 BART analysis.

Q. **What was OG&E's original conclusion for BART after reviewing all the options for complying with Regional Haze requirements for SO_2?**

A. After reviewing all options, the BART determination concluded that the continued use of low sulfur coal, that OG&E was already utilizing, was the most appropriate method for controlling SO_2 emissions. This conclusion was supported by the ODEQ and was submitted to EPA as part of the SIP.

Q. **What was EPA's ruling regarding the SIP for complying with SO_2?**

A. The EPA, as mentioned previously, did not accept Oklahoma's compliance plan and rejected low sulfur coal as being BART.

Q. **Following the ruling by EPA rejecting low sulfur coal as BART, did OG&E perform any other analysis of post-combustion technologies?**

A. In light of the EPA FIP, OG&E proactively researched the feasibility of DSI. This research included discussions with vendors, engineering firms, and other utilities, as well as conducting extensive research at both OG&E coal facilities over a two year period utilizing mobile testing facilities. The results of this testing indicated that reduction levels required by the EPA FIP could not be consistently achieved by this technology at our facilities. Testing also showed that maximum injection rates used during these tests created significant operational concerns related to electrostatic precipitator operation. OG&E also began a more thorough evaluation of other post combustion technologies.

Q. **Can you please describe the various technologies evaluated by OG&E after the EPA rejected the SIP?**

A. The Dry FGD technologies evaluated were SDA, CDS and a proprietary dry technology identified as NID™. OG&E also revisited Wet Scrubbers. These technologies were evaluated for the benefits and limitations of each technology type and comparative order of magnitude costs for each type. From the initial evaluation, NID™ was eliminated from further consideration due to physical limitations and operational complexity.

Using the Kepner-Tregoe decision making process, OG&E evaluated Wet Scrubbing technology and two different Dry Scrubbing technologies, SDA and CDS.

The three alternatives were compared and scored against criteria. CDS ranked highest, with SDA a reasonably close second. Wet Scrubbing technologies were ranked a distant third and eliminated from further consideration. CDS and SDA were then further evaluated for risk.

Based on the scoring evaluation and risk assessment, CDS was recommended, pending site visits to generating stations using CDS technology. The purpose of these visits was to verify assumptions used in the evaluation and risks considered. Although not part of the evaluation criteria, feedback from the operating utilities that were visited was also solicited on their experiences with the CDS technology. OG&E visited two stations and the result of those visits was to validate the selection evaluation of CDS. Given this evaluation, OG&E selected CDS as the FGD technology to use.

Q. **How have the cost estimates for dry scrubbers changed over time?**

A. The initial 2008 capital cost estimates for a SDA scrubber at Sooner, as developed by S&L, is shown on Table 2, above, and was $390 million. In response to ODEQ questioning, the S&L SDA Dry Scrubber estimate was updated and the refined cost estimates were provided to ODEQ in December 2009. This revised capital cost estimate for a Sooner unit was $242 million, without AFUDC. The 2009 conceptual cost estimates were based on SDA technology project-specific vendor quotations for certain major equipment items and inputs developed by performing preliminary project engineering. S&L represented these 2009 conceptual cost estimates to be in the +/-20% accuracy range.

OG&E is currently evaluating bids from several vendors for supply and installation of CDS scrubbers and expects to finalize the cost by the end of 2014. The most recent capital cost estimate done in July 2014 for both Sooner units is [redacted] +/-10%. This number represents a combination of firm price equipment bids for the CDS hardware and preliminary pricing from potential installation contractors. In addition, the O&M costs, assuming a unit capacity factor of 70%, are estimated to be approximately $30 million annually.

Q. **Did OG&E consider switching from coal to natural gas as a compliance alternative?**

A. Yes. In fact, the Oklahoma SIP filed in February 2010 included a provision that made fuel switching on two coal units a potential option available to the Company.

Q. **Do the emission rates for fuel switching to natural gas meet SO_2 emission limits required in the Regional Haze FIP?**

A. Yes, a fuel switch from low sulfur coal to natural gas will result in emissions rates that meet the Regional Haze FIP. The FIP dictates an emission rate of 0.06 lbs/MMBtu for SO_2. A fuel switch to natural gas will result in an emission rate of 0.01 lbs/MMBtu, which is well below the Regional Haze FIP limit.

Q. **What options has OG&E explored associated with fuel switching to natural gas?**

A. OG&E explored the costs and implications of both converting our coal units to burn natural gas and installing new natural gas combined cycle units. Specifically within the last year, OG&E has commissioned a feasibility study for converting our coal units to burn natural gas. This study explored the various design modifications, performance implications and associated costs of conversion.

Q. **How were the cost estimates for natural gas conversion developed?**

A. The natural gas conversion estimate was predicated on information provided by the original equipment manufacturer and is an indicative pricing estimate for feasibility purposes. The current estimate for natural gas conversion is approximately [redacted] per unit. This does not include the cost of any minor balance of plant modifications that would be necessary as a result of the fuel switch.

Q. **Please describe how the cost estimates for installing a new combined cycle natural gas plant were developed.**

A. OG&E contacted S&L to obtain cost estimates for installation of new natural gas combined cycle units. The estimates provided by S&L ranged from approximately $1,200-1,440/kW, or approximately $720 million for a 500 MW unit. This estimate

excludes owner related costs, associated with items such as environmental permitting, legal fees and project management.

Q. **After reviewing its alternatives, what is OG&E's plan for meeting the SO_2 Targets identified in the FIP?**

A. As described in the 2014 IRP Update submitted by the Company on August 4, 2014 and discussed further by OG&E Witness Howell, OG&E's environmental compliance plan is to install CDS on Sooner Units 1 and 2 and convert Muskogee Units 4 and 5 to burn natural gas. This approach strikes a balance by meeting the requirements of the RHR while maintaining a level of fuel diversity, helping to insulate our customers from the volatility of fuel prices. The plan has the additional benefit of positioning OG&E to respond to future emission regulations as identified in the testimony of OG&E Witness Turner.

Q. **Why has OG&E selected the Sooner plant over Muskogee to install FGDs?**

A. The Sooner plant has several benefits. The Sooner units are newer and by design more efficient than the Muskogee Units. Also, the Sooner site was designed to enable expansion for additional units and as such has land area and space availability that is more conducive to expansion and installation of the FGD systems.

Additionally, Muskogee already has a portion of the natural gas infrastructure to support gas conversion and is designed to have gas in the facility. Adding gas to Sooner would necessitate a review and potentially major upgrades to support the safety requirements associated with natural gas operation.

Q. **What is the current status of implementation of this plan to meet the SO_2 FIP requirements?**

A. OG&E has developed specifications and bid documents and has issued Request for Proposals ("RFP") to various vendors for the equipment and installation of Dry Scrubbers at both coal stations. The proposals have been received, the evaluation process is ongoing and we expect to complete negotiations and sign all contracts by the fourth quarter of 2014.

With regards to gas conversion of Muskogee Units 4 and 5, OG&E is in the process of selecting an architect-engineer ("AE") to develop specifications for bidding this work. OG&E will then solicit RFP's from various vendors, for equipment supply and installation. Our intent would be to perform evaluations of bids and award the project in advance of the RHR compliance date of January 4, 2019.

C. TECHNOLOGICAL OPTIONS FOR MEETING REQUIREMENTS OF MATS

Q. **How does OG&E plan to comply with MATS Targets for PM, HCL and mercury?**

A. OG&E has performed testing of its coal units as recently as 2013 and will be in compliance with the MATS Targets for PM and HCL. Therefore, no additional environmental control equipment is required. However, uncontrolled mercury emissions on OG&E coal fired units exceed the 1.2 lbs/TBtu compliance limit specified in the MATS Targets and additional technology is required to meet the standard. Currently, uncontrolled mercury emissions from OG&E coal units average approximately 6 lbs/TBtu.

Q. **What are the technological options and OG&E's plan for complying with the mercury emission limits required in the MATS Targets?**

A. Activated Carbon Injection ("ACI") is the most common method of controlling mercury emissions. With ACI, Powdered Activated Carbon ("PAC") is pneumatically injected into the flue gas stream upstream of the particulate collection equipment. Mercury in the flue gas is absorbed by the PAC. The PAC, along with other particulate matter (fly ash), is removed in the existing electrostatic precipitators.

An alternative method consists of adding halogen based chemicals, either as a fuel additive or injected into the furnace, which react with the products of combustion. However, use of these chemicals in this method carries a significant risk of rapid corrosion that can cause extensive damage to components and ductwork in the flue gas path.

From the available alternatives, OG&E has selected the ACI method for complying with mercury emission limits.

Q. **Please discuss the systems and equipment that are needed for the installation of ACI.**

A. The equipment to be added for ACI includes the construction of silos to store PAC, piping and associated blowers, feed systems, filters and injection lances. The equipment will be controlled though each units DCS. PAC is delivered to the site by truck and is pneumatically unloaded into a storage silo. Fluidization air is added to a silo and promotes flow of ACI to the unit as required to control emissions. Fluidized PAC flows from a silo cone through a series of feeders that control the amount of PAC injected into the flue gas. After progressing through the feeders, the PAC passes through an eductor. A blower provides conveying air to move the PAC through a piping system and into an array of injection lances that disperse the PAC evenly into the flue gas ductwork, upstream of the particulate control device.

Q. **What does ACI cost to construct, operate and maintain?**

A. Conceptual cost estimates were developed for the two Sooner units and the three Muskogee units, based on S&L's in-house cost estimating database for similar equipment. The installed capital costs are estimated to be approximately $9.7 million for the two Sooner units and $14.6 million for the three Muskogee units.

Based on an 80% capacity factor, the total annual operating costs, comprised of O&M labor and materials, powdered activated carbon reagent, and fly ash disposal costs, were estimated as $17.9 million per year for Sooner and $26.8 million per year for Muskogee. After Muskogee units 4 and 5 are converted to natural gas at the end of 2018, the O&M cost for ACI at the Muskogee 6 unit will be approximately $8.9 million. O&M cost estimates were based on the use of halogenated PAC at an injection rate of 5 lbs/MMacf.

Q. **What is the status of implementation of this plan?**

A. OG&E has developed specifications and bid documents for ACI. These documents were used to solicit equipment bids from various vendors leading to the selection of the lowest evaluated bid. This bid is from [redacted]. Contract negotiations have begun with this vendor

and we expect a contract to be signed by the end of 3Q 2014. OG&E will be soliciting bids for equipment installation later this year with the intent of beginning construction upon receiving final permits. Permit applications were submitted to the ODEQ in June 2014 and we expect final permits sometime later in 2014. Final costs for both equipment and installation will not be available until Q1 2015. However, we do not anticipate a significant price difference from the original estimate. The equipment will be delivered, installed and optimized during 2015 in time to support the compliance date of April 16, 2016.

III. MUSTANG PLANT MODERNIZATION

Q. **Please describe the Mustang Generating Facility.**

A. The Mustang Generating Facility is located on the west side of Oklahoma City in Oklahoma County, Oklahoma. It has four steam electric generating units that are designated as Mustang Units 1, 2, 3 and 4. The approximate total generating capability from this facility is 460 MW. Mustang Units 1 and 2 became operational in 1950 and 1951, respectively. Mustang Unit 3 became operational in 1955 and Mustang Unit 4 became operational in 1959. The Mustang plant is the oldest plant in OG&E's fleet. All four units utilize natural gas as their fuel source.

Q. **What is the current age of the existing Mustang units and what is the estimated retirement schedule for those units?**

A. The current age and estimated retirement schedule for the Mustang units can be seen in Table 4, below.

Table 4: Mustang Units Age and Retirement Dates

Unit Designation	Current Unit age (Yr)	Estimated Retirement date (year-end)
Mustang 1	64	2015
Mustang 2	63	2017
Mustang 3	59	2017
Mustang 4	55	2017

Q. **What is the basis for the estimated retirement dates for Mustang units 1 and 2?**

A. OG&E engaged Burns and McDonnell ("B&M"), an engineering firm, to research and recommend retirement dates for OG&E's older steam gas units to be used as a basis for planning. B&M recommended that an operating age of 65 years be used as a retirement date and that these dates represented a "maximum" expected life. The basis of their recommendation was derived from an internal review of OG&E's fleet as well as professional judgment and industry available information. At the time of this review, when B&M reviewed 2008 Energy Information Administration ("EIA") industry information, only 15 of over 400 operational units greater than 10 MW were older than Mustang Unit 1. Since that time, 6 of the 15 units have been retired.

Q. **Does OG&E have any recent information that supplements the original recommendations from B&M?**

A. Yes. According to updated retirement information obtained from SNL earlier this year, many generating units have been retired well before 65 years and the average and median retirement age of gas fired units across the U.S. is between 45-49 years old.[3] As an example, from 2010 through 2012, Entergy retired 15 gas fired steam units with commercial operation dates from 1943 to 1965[4]. The average age of these units were 54 years. Additionally, Exelon announced in December 2013, its plan to retire a 62 year old 74 MW gas unit due to its age. Altogether, very few gas fired units in the United States operate past 65 years. Based upon similar class/size of units, there are only 6 out of 58 operating units older than Mustang unit 3 operating today. There are no other units of a similar class/size and older then Mustang unit 4 still in operation.

[3] SNL Financial LC is a nationally recognized business intelligence company. The company focuses its research on business sectors including energy, banking, financial services, media and communication, insurance, and real estate. It collects, standardizes and disseminates all relevant corporate, energy, financial, market, and mergers and acquisition data using a wide variety of public sources such as SEC, FERC, EIA, etc. SNL has 24 offices worldwide.

[4] According to FERC Form 860.

Q. **What is the basis for the retirement dates for Mustang units 3 and 4?**

A. In addition to the fact that these are the oldest units in the OG&E fleet and some of the oldest in the entire country, the basis of retirement dates for Mustang 3 & 4 are associated with both industry information and concern of unit reliability. After considering this information, OG&E concluded that continuing to operate Mustang units 3 and 4 beyond 2018 would likely require an increased level of investment due to age and their current mode of operation, but even with needed investment in key areas, the units are at a greater risk of catastrophic failure as many key components are approaching or exceeding their design life.

Q. **Please discuss the type of components that are at risk of catastrophic failure.**

A. Certain components in units of this age are more susceptible to catastrophic failure. These components include items such as pressure containing parts, high voltage equipment and high speed rotating equipment. The risk of component failure due to age could also create a greater safety risk for our employees.

To illustrate our concern, OG&E experienced a cracked rotor in 2010 during the startup of Mustang unit 4 that could have led to a catastrophic event. The operations staff noticed unusual turbine vibrations and investigated. The investigation revealed that the unit had a cracked low pressure turbine rotor. The machine was opened and resulted in the unit being offline for three months while repairs were made. The part for the repair was provided by the original equipment manufacturer, Siemens. If not for the availability of this older rotor part, the repair cost would have been much greater and duration would have been up to 18 to 24 months. If the unit was actually brought online with the cracked rotor, it likely would have failed rendering the machine inoperable and/or irreparable. This risk still exists with the other components for this machine due to age. The same risks exist for all of the Mustang units.

Q. **Are there any reliability impacts that would result from the component failures described above?**

A. Yes. If failure were to occur in one of several major components such as the turbine, boiler headers or a generator step up transformer, the units could be off line for up to 2

years. Parts for units of this age are often non-existent, not supported by manufacturers or were produced by manufacturers that are no longer in business. This often requires that parts must be reverse engineered and specially made at a significant expense and delay.

Q. **What other factors contributed to your decision to retire these units?**

A. The Mustang units have become technically obsolete. Technical obsolescence occurs when an asset is outdated and cannot meet a new need and new technology exists that is better suited for meeting this need. Failure to be able to function in a required/desired role adversely affects the usefulness of the asset and the value to the customer.

The Mustang units were originally designed for base-load type operation. They ran this way until the 1980's when the OG&E coal units became operational. As they have aged and as OG&E and others have obtained newer technologies elsewhere (*i.e.*, CC's) they have shifted their operating mode to more off and on cycling and intermittent mode of operation. As an example, Mustang 4 from the late 80's until 2006 operated in more of a mid-merit type mode (filling the gap between base load coal units and peaking units). In recent years, the Mustang units have experienced more seasonable/mid-merit operation. With the integration of the OG&E fleet into the Southwest Power Pool ("SPP") Integrated Marketplace ("IM"), we anticipate the Mustang units, with their relatively higher cost, to operate in the 5% capacity factor ("CF") range and may see a much greater amount of cyclic and intermittent duty. The existing Mustang units, because of their design, are not well suited for this cyclic mode of operation, which will tend to greatly shorten their remaining useful life and further increase the risk of unplanned outages.

Q. **What are the effects of frequently cycling units off and on that were originally designed for baseload or load following operation?**

A. The effects of frequent cycling are well known within the industry. Cycling units off and on creates significant thermal stresses on pressure components and rotating machinery. These increased stresses tend to reduce the lifecycle of such components and cause

premature failures. This tendency increases with the age of the asset and the number of cycling events.

Q. **Is the decision to retire Mustang by year-end 2017 consistent with OG&E's past approach as it relates to the retirement age of gas fired steam units**?

A. Yes. OG&E has retired a number of gas-fired steam units over its 112 year history. Since the early 1980's OG&E has retired several gas-fired units including Muskogee unit 3, the Arbuckle Plant, the Osage Plant, and the Belle Isle plant. The average retirement age of these OG&E gas-fired steam plants was 51 years old.

Q. **When the Mustang units are retired, how will OG&E replace the generation?**

A. OG&E will replace these vintage gas fired steam units with new gas fired CTs having approximately the same capacity at the Mustang site.

Q. **Why did OG&E select the Mustang site to locate new generating units?**

A. The Mustang site offers several advantages to OG&E. Those advantages include being in close proximity to OG&E's largest load center, having an established infrastructure in place, having a trained and experienced workforce and having existing environmental permits.

Q. **Please explain the advantages the existing Mustang site has with respect to its proximity to the load center.**

A. Maintaining generation at this location is very important to OG&E system operations. The Mustang site already has an existing robust high voltage transmission system in place. This results in better reliability of the transmission grid as opposed to locating the new generation at a more remote location. Generation close to the load source reduces line losses, reduces line congestion and cost, supports voltage control, and facilitates our system restoration plan.

Q. **What are some of the other operational advantages of the existing Mustang site?**

A. The Mustang site already has the overall infrastructure needed to support a generating facility, *i.e.*, secure property, existing roads; facilities to support maintenance and operation, water supply/water rights; fuel supply facilities as well as existing transmission infrastructure. This avoids the significant expense and need to develop a completely new site and infrastructure. Additionally, the Mustang site is currently staffed with a highly skilled/trained workforce.

Q. **Can OG&E utilize Mustang's existing environmental permit to the benefit of customers?**

A. Yes. The Mustang site already has the environmental permits necessary for operation. We currently have a window of opportunity to use the emissions allowed in the existing air permit to support the permitting of the new units through a process generally referred to as netting. OG&E Witness Turner explains this process in more detail in her testimony. This process typically allows for quicker permitting and in turn a shorter project timeline. The amount of replacement generation that can be constructed under a netting analysis is dependent on the historic emissions from the existing units. OG&E anticipates that the Mustang units will be utilized less in the SPP Integrated Marketplace. This reduced utilization means that the emissions that can be used in any netting analysis will go down over time. If OG&E waits until after mid-2015 to file its permit for the new CTs, OG&E may not be able to permit all 400 MW needed by the Company.

Q. **When does OG&E need to begin the CT development process in order to meet the 2018 in-service date?**

A. In order to have the new CTs in service before the summer of 2018, OG&E needs to begin preparing the ODEQ application no later than December of 2014.

Q. **Please explain why the process of preparing the application should start at that time.**

A. The Company cannot begin installation of the replacement CTs at Mustang until a construction permit is issued by ODEQ. To file the initial permit application, OG&E must be close enough to executing contracts for the new Mustang CTs to have near final turbine specifications, so specific emission profiles for the units can be included the application. After receiving the initial application, ODEQ will review information we have provided and request additional information or modifications before ultimately designating the permit application as complete This review and request for changes process between ODEQ and OG&E can involve multiple iterations and up to two months. Once the application is complete, ODEQ will begin to process that application into a draft permit. Moreover, once the permit application is deemed complete and a draft permit has been issued, several steps of agency review and public participation are required. OG&E expects that these steps could take another year to complete before a final permit is issued.

The amount of CT capacity OG&E can locate at the Mustang site is dependent on a netting process that involves the history of emissions at the plant over the 60 months prior to a complete permit application. Based on that emission history for the existing units, the ability to maximize the generation begins to decrease after July 31, 2015. If OG&E fails to have a permit application filed, reviewed and deemed complete by that date, the amount of replacement generation will also begin to decrease.

OG&E must complete permitting, engineering, procurement, construction and startup of the new CTs prior to the units being in service for the summer of 2018. This entire process, from permitting to in-service date is anticipated to take 44 months, thus making it difficult to meet the summer 2018 need if OG&E does not advance this process beginning as soon as possible.

Q. **Please describe the type of units OG&E intends to install at the Mustang site and the associated benefits of such units.**

A. The new units will be a class of assets referred to as simple cycle CTs. These CT's have the ability to be turned off and on quickly. This allows them to supply power during

peak, to serve unscheduled demand and to supply ancillary services to the grid, such as operating reserves. These units will deliver better reliability, improved efficiency, better load response, improved operational flexibility and lower emission rates.

CTs resemble a jet engine, in that air flows through a compressor that brings it to a higher pressure. Energy is then added by spraying fuel (natural gas) into the air and igniting it so the combustion generates a high pressure, high-temperature flow that expands through a turbine. The turbine is connected by a shaft to a generator, which produces electricity. OG&E's 2014 IRP Update explains how CTs were selected.

Q. **Will CTs be dispatched differently in the SPP IM than they were when OG&E served its own load?**

A. Yes. As an example, our Horseshoe Lake Units 9 and 10, which are similar to the new Mustang units have been called to start 54 times from the market inception on March 1, 2014 to July 2, 2014, a period of just over four months. These same units averaged 63 starts per year over the previous three years, representing a two and one half times increase in the number of starts per year. The new Mustang units will increase the asset diversity of the OG&E fleet by increasing our CT capability from 176 MW to 576 MW.

Q. **What characteristics of the new units make them more likely to be dispatched in the SPP IM?**

A. The capability of a generating unit to respond to system demand is indicated by two measures: start up time and ramp rate. Startup time indicates the length of time required to take the unit from an offline, cold state to full capability. Ramp rate indicates the rate at which the unit can change output once in service measured in megawatts per minute. Both of these performance characteristics offer value to the system in the ability to operationally respond to system needs. The CTs being installed at Mustang typically can provide a startup time of 10 minutes compared to a minimum of 10 hours for the existing Mustang units. The comparative ramp rate performance for the replacement CTs is approximately 10 MW/minute versus an average of 2.0 MW/minute for the existing Mustang units. In both cases, the combustion turbine technology offers significantly improved performance on load response. These units are designed to start multiple times

per day if needed to match the peaks in the market and respond to unexpected and unscheduled changes in demand that can occur. The faster response offers significantly improved ability to respond to the variability of intermittent resources such as wind and solar.

Q. **Can OG&E quantify the benefit to customers from the improved efficiency of the new Mustang units?**

A. The average difference in heat rate between the existing Mustang units to a new combustion turbine is approximately 1,516 Btu/kwh. Using a recent gas price of $4.50/MMBtu, this amounts to a savings in fuel to the customer of $2,729 for every hour the new CTs would run compared to the existing Mustang units, or approximately $1.2 million per year assuming a capacity factor of 5 percent. If the capacity factor increases above 5% then the savings would be greater.

Q. **Will the new units at Mustang have a lower emission rates for certain pollutants?**

A. Yes. The NO_X emission rate in lbs/MMBtu will be approximately 57% lower than the NO_X rate from the existing Mustang units. This reduction is based on a comparison of the predicted new unit NO_X rates and the average NO_X emissions from the existing Mustang units for the years 2009 – 2013.

Emission rates for new units for Carbon Monoxide ("CO") will also be approximately 53% less than the existing Mustang units for the years 2011-2013. Other pollutants also show decreased emission rates with PM being approximately 73% less and Volatile Organic Compounds ("VOC") being approximately 97% less for the same period.

The Carbon Dioxide ("CO_2") emission rate in lbs/MMBtu for the new units will be slightly less than the emissions rate for the existing units, and the CO_2 produced per MWh will be less as well. This is the result of an improved heat rate for the new units as compared to the existing Mustang units.

Q. **What is the estimated cost of these new units?**

A. S&L provided the Company the estimated capital cost of the 40 MW CTs to be [redacted].

Q. **Where is OG&E in the development process for CTs at the Mustang plant?**

A. OG&E is conducting a technology assessment to aid in its selection of the appropriate CT characteristics and size class. Based on OG&E's technology selection, bid documents will be issued for competitive bidding by the end of the 3Q 2014. This process will continue to refine the cost estimate for this project.

Q. **When does OG&E expect the new units to be operational?**

A. OG&E's plan is to engineer and construct these units in a manner that makes the new units operational beginning in 2018.

IV. CONCLUSION

Q. **Please summarize your testimony.**

A. My testimony provides an overview of the OG&E generating facilities that are affected by the Regional Haze Rule, along with associated state and federal plans, and the MATS Rule. I have also explained the various technological options OG&E explored for complying with the emission limits imposed on the Company through these two Rules and how the Company evaluated these options based on effectiveness, cost and timing. I explained OG&E's decision to replace its four units at the Mustang generating facility with new CTs, including the benefits to the Company and its customers.

Q. **How does OG&E plan to manage the costs and oversee the execution of the projects included in the Company's environmental compliance plan?**

A. OG&E will utilize a program director and project managers who have experience with the procurement and construction of similar size and scope projects. Multi-discipline teams will be established for each of the projects to oversee the procurement, construction, startup and commissioning of these projects. All projects will follow

OG&E's procurement practices and the equipment and installation will be competitively bid and evaluated by an OG&E multidiscipline team.

Q. **What activities are critical for OG&E to meet the compliance deadline for RHR and MATS at the lowest reasonable cost for customers?**

A. OG&E believes the best option for meeting the EPA's deadlines at the lowest reasonable cost to our customers involves locking in major contracts in early 2015. By far the largest of the environmental compliance projects is the FGD equipment installations for the coal units. The deadline for these installations is firm and compliance involves completing projects that must be very carefully engineered, planned and executed. Executing contracts in early 2015 for parts, equipment, and installation contractors allows the Company to minimize the exposure to escalations in commodity costs, loss of fabrication queue priority, and other major events that could substantially increase the costs of compliance.

In addition, execution of contracts for the new Mustang CTs in the first quarter of 2015 would allow OG&E to be confident that the new units could be manufactured, installed and in service by the Summer of 2018. If OG&E is not able to bring the new CTs into service for the 2018 summer season, the Company would be required to purchase capacity to satisfy SPP planning requirements. Also, if the CTs are not online by the Summer of 2018, OG&E could also face the prospect of higher net SPP IM energy costs to customers.

Q. **Does this conclude your testimony?**

A. Yes.