BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	
AUTHORIZING APPLICANT TO MODIFY ITS	)	CAUSE NO. PUD 201800140
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

Direct Testimony

of

Robert J. Burch

on behalf of

Oklahoma Gas and Electric Company

December 31, 2018

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 Managing Director, Utility Technical Support. I began my career with OG&E in 2012.

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

A. I have been employed by four electric utility companies, a specialty chemicals refinery and a nationwide food manufacturing company over the last 33 years in several 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. Prior to my tenure with Duke, I was employed for over 10 years by Reilly Industries (Specialty chemicals refiner). Other employers include, Nabisco Foods, Hoosier Energy REC and Illinois Power Company. I received a Bachelor of Science degree in Mechanical Engineering in 1985 from Rose-Hulman Institute of Technology.

Q. **Have you previously testified before this Commission?**

A. Yes. I testified in Cause Nos. PUD 201400229 and 201700496.

Q. **What is the purpose of your testimony?**

A. My testimony provides an overview of the OG&E generating facilities that are affected by the Regional Haze Rule, specifically those affected by the Federal Implementation Plan ("FIP") for sulfur dioxide ("SO_2") emissions. I then explain how OG&E explored various technological options for complying with the emission limits imposed on the Company through the Regional Haze FIP and how the Company evaluated these options based on effectiveness, cost and timing. Next, I summarize the progress to date on the OG&E plan.

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

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

A. The Regional Haze FIP affects four OG&E coal-fired generating units (Sooner Units 1 and 2 and Muskogee Units 4 and 5). Muskogee Unit 6 was not in existence prior to August 1977 and therefore is not affected by the Regional Haze Rule ("RHR"). OG&E Witness Usha Turner provides greater detail on Regional Haze FIP.

Q. **What portion of OG&E's total generating capacity do these facilities represent?**

A. OG&E owns approximately 6209 MW of fossil fuel generating capacity (not including capacity purchases from AES Shady Point and Oklahoma Cogeneration). The OG&E generation facilities affected by the Regional Haze FIP total approximately 2030 MW. This equates to approximately 33 percent of OG&E's total owned fossil fuel generating capacity.

Q. **Please describe the Sooner Generating Station?**

A. The Sooner Generating Station is located near the City of Red Rock, Noble County, Oklahoma. It includes two steam electric generating units of approximately 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 plants is obtained from mines in the Powder River Basin ("PRB") area of Wyoming and shipped to the plant via the Burlington-Northern Santa Fe railroad. The coal quality obtained is among the cleanest coal available from a sulfur content perspective. This plant is operated by a team of approximately 125 experienced craftsmen, professional and managerial personnel. These people are predominantly located in nearby communities.

Q. **Describe the Muskogee Generating Station?**

A. The Muskogee Generating Station is located near the City of Muskogee, Muskogee County, 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 plants is obtained from mines in the PRB and shipped to the plant via the Union Pacific railroad. When operated as a three-unit coal plant the facility is staffed by a team of approximately 175 experienced craftsmen, professional and managerial personnel. These people are predominantly located in nearby communities.

Q. **Please briefly describe the Regional Haze Rule**

A. The RHR is an environmental regulation intended to restore pristine visibility to national parks and wilderness areas by 2064. To achieve those levels this rule targets emissions of SO_2 and nitrogen oxide ("NO_X") from certain electric generating units, depending upon their year of construction.

Q. **Has OG&E achieved compliance with any part of the Regional Haze Rule**

A. Yes. OG&E has achieved compliance with emissions limits for NOx set by the Regional Haze Rule by installing low NOx burners on seven generating units including Sooner Units 1 and 2, Muskogee Units 4 and 5 and all three units at Seminole.

Q. **What are the SO2 emission limits prescribed by the Regional Haze FIP?**

A. As described in greater detail by OG&E Witness Usha Turner, the Regional Haze FIP requires OG&E to meet an emission limits for SO_2 of .06 lb/ Million BTU of fuel input.

Q. **Why did OG&E receive a FIP for SO2 emissions under the Regional Haze Rule but not for NOx emissions?**

A. The State of Oklahoma submitted a State Implementation Plan ("SIP") to the EPA to demonstrate compliance to the Regional Haze Rule. The EPA accepted the Oklahoma SIP for NOx emission but rejected it for SO_2 emissions. Ultimately, after a long court battle, a FIP for SO_2 emissions were issued containing the .06 lb/ Million BTU of fuel input limit on SO_2 emissions.

Q. Did OG&E agree with the EPA's decision to issue a FIP for SO_2 emissions?

A. No. OG&E and the State of Oklahoma both disagreed with that decision and filed various appeals through the federal court system ultimately appealing to the United States Supreme Court. Unfortunately, the appeal was not successful, and OG&E was required to comply with the FIP.

Q. Did OG&E customers see any benefit to delaying an SO_2 compliance date because of the time needed for the legal process to unfold?

A. Yes. During the time required to fully pursue the legal appeal process, OG&E had a legal stay in place which effectively extended the compliance date. During this time, OG&E was not deploying capital and not incurring operating expenses associated with the scrubbers. Both led to customer savings.

In addition, the time needed to fully unfold the legal process allowed the scrubber procurement and installation market to come off of its peaks. This led to more competitively priced equipment and construction labor than might have otherwise been seen during the peak of the market leading to additional customer savings.

TECHNOLOGICAL OPTIONS FOR MEETING THE 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 pounds per MMBtu of SO_2 for 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 are designed to reduce overall SO_2 emissions and 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.

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

A. As described earlier, the various Pre-combustion options for reducing SO_2 consist of coal switching, coal washing and coal processing. Lower sulfur coal results in lower SO_2. Several coal fired utilities have switched to low sulfur coal as an SO_2 emission control strategy. 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 one Pre-combustion method that has been 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. Coal washing is generally done at the mine to maximize the value of the coal and reduce freight charges to the power plant. OG&E coal units are designed to utilize low sulfur coals. Based on a review of available information, no information was identified regarding the washability or effectiveness of washing subbituminous coals. According to Sargent & Lundy ("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.

Lastly, we investigated the option of coal processing. 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 Best Available Retrofit Technology ("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, or a best practice.

Q. **Please describe the various Post-combustion technologies reviewed by OG&E**

A. Post-combustion technologies generally fall into two classifications, Wet-FGD ("Wet Scrubber" or "Wet Scrubbing") and Dry-FGD ("Dry Scrubber" or "Dry Scrubbing") systems.

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") systems, Dry Sorbent Injection ("DSI") systems, and Circulating Dry Scrubber ("CDS") systems.

Q. **Did OG&E perform an evaluation of the different Post-combustion scrubber technologies and arrive at any conclusion?**

A. Yes. OG&E was required to perform a BART analysis under the RHR. 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 technologies 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 1

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.

DSI was also evaluated during the BART analysis, but because the control efficiency of the DSI system is lower than that of FGD systems, this technology was not reviewed any further at that time.

Q. **Are there any other alternatives that OG&E has investigated?**

A. Yes, OG&E explored fuel switching to natural gas.

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

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 lb/MMBtu for SO_2. A fuel switch to natural gas will result in an emission rate of 0.01 lb/MMBtu, which is well below the Regional Haze FIP limit.

Q. **What options did OG&E explore 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, OG&E commissioned a feasibility study of converting our coal units to burn natural gas. This study explored the various design modifications, performance implications and associated cost of conversion. Additionally, OG&E contacted engineering consultants S&L and

Burns & McDonnell (“B&M”) to obtain cost estimates for installation of new natural gas combined cycle units. The information on both above options was provided to our resource planning group for evaluation.

Q. **How were the cost estimates for natural gas conversion and new natural gas combined cycle units developed and what is the level of accuracy of those estimates?**

A. The natural gas conversion estimate was provided by ALSTOM, the original equipment manufacturer (“OEM”) and is an indicative pricing estimate for feasibility purposes. The estimate for natural gas conversion, developed at that time, was approximately $36M per unit. This does not include the cost of securing needed natural gas transportation service to the plant.

Cost estimates for new natural gas combined cycle units were provided by S&L for use as input to resource planning models. Capital cost data is based on S&L previous project experience. The estimates provided by S&L ranged from approximately $1200-1475/KW, excluding owner related costs, associated with items such as environmental permitting, legal fees, project management, etc. The natural gas conversion estimate (study level estimate) and S&L’s capital cost estimate for new natural gas combined cycle units have an accuracy of -30%/+50%.

Q. **What was OG&E’s 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 Oklahoma Department of Environmental Quality (“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 the 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 scrubber technologies?**

A. In light of the EPA FIP, OG&E resumed proactively researching the feasibility of FGD by means of DSI. This research included discussions with vendors, engineering firms, and other utilities, as well as performing research testing at both OG&E coal 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.

Q. **Can you please describe the dry technologies evaluated by OG&E and how you arrived at this decision?**

A. The dry technologies evaluated were SDA, CDS and a proprietary dry technology identified as NID™. 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, Wet scrubbing technologies, SDA, and CDS FGD alternatives were compared and scored against criteria. The results of the scoring ranked the FGD technologies. 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. Feedback from the operating utilities that were visited was also solicited on their experiences with the CDS technology that was not part of the evaluation criteria. OG&E visited to 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 were the initial cost estimates developed for the dry scrubbers and what is the level of accuracy of those estimates?

A. The initial BART cost estimates for scrubbers were developed by S&L based on detailed costs estimates for similar projects, see Table 2. Capital costs were compared to EPA's Coal Utility Environmental Cost Workbook, modified to account for any recent increases (at the time of the evaluation) in purchased equipment and commodity costs. In response to ODEQ questioning, the 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, not including AFUDC. The 2009 conceptual capital cost estimates were based on SDA technology project-specific vendor quotations for certain major equipment items and inputs developed by performing preliminary project engineering. The 2009 study level capital cost estimates are in the -10 to +25% accuracy range.

Q. How is OG&E meeting the SO_2 Targets as identified in the FIP?

A. OG&E is installing FGDs on Sooner Units 1 and 2 and converting 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. This approach will partially insulate our customers from the volatility of fuel prices and the cost of pending environmental regulations. 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 was the Sooner plant selected for FGD installations and the Muskogee plant selected to be converted to natural gas?

A. Sooner was selected over Muskogee for the installation of FGD units based on several factors. The Units at Sooner are newer than Muskogee Units 4 and 5 and have a better design heat rate than the Muskogee units. Additionally, the site at Sooner is much larger and less congested since the site was originally designed as a six unit site. This extra room greatly facilitated the efficient execution of a large construction project. The inefficiencies of the Muskogee sight would have resulted in a higher installed cost for customers.

Q. **Please describe the equipment and processes involved with the CDS units at Sooner.**

A. The Sooner CDS project involves the installation of a two train circulating dry scrubber vessels on each of the Sooner units. The CDS reactors are large vessels installed immediately after the existing electrostatic precipitators and contain the chemical reaction that reduces the sulfur dioxide in the flue gas. The chemical reaction consists of passing flue gas through a suspended bed of hydrated lime where the sulfur reacts with the calcium in the lime to form a mixture of calcium sulfites and calcium sulfates. The flue gas then passes through a pulse jet fabric filter ("PJFF") which then separates the clean gas from the solid waste products in much the same way a dust bag works in a vacuum cleaner. A portion of the solid waste product is recirculated back to the CDS vessel so that any unreacted lime can be fully utilized. The remaining waste products are removed for disposal in a landfill. Clean flue gas leaves the PJFF to enter a new set of induced draft fans that provide the motive force to move the clean gas up the stack. The equipment is connected together with new insulated ductwork.

In addition to the construction of the CDS units, the Sooner project involves the installation of facilities to unload, store and process pebble lime (limestone) into hydrated lime used in the CDS reaction. Similar storage and loading facilities have been constructed to hold and remove waste byproducts from the plant site.

Q. **Please describe the project execution plan and contracting strategy for the Sooner CDS project.**

A. Once the technology selection process identified CDS as the preferred scrubbing technology, OG&E had its owners engineer, S&L, create a performance specification for the procurement of two CDS systems. That specification was the basis for a competitive bidding event that resulted in Andritz winning the contract for providing the CDS systems.

Concurrent with the CDS procurement, S&L also prepared a specification to procure Engineering, Procurement and Construction ("EPC") services to execute the project with the Andritz contract being assigned to the successful bidder. A competitive bidding event was conducted for EPC services and a contract was awarded to Oklahoma Power Constructors ("OPC"). OPC is a joint venture between Black and Veatch (an Engineering firm) and PCL constructors (an industrial contracting firm).

The contract between OG&E and OPC is a fixed price contract based on an agreed scope of work with OPC carrying the cost, schedule, and performance risk.

Q. **Can you give a sense of the materials and effort required to successfully complete the Sooner CDS project**.

A. Yes. The Sooner CDS project involves the placement of 12,600 cubic yards of concrete, 5,600 tons of structural steel, 93,000 linear feet of piping, 38,000 linear feet of electrical cable tray and 1,300,000 feet of electrical cable. To put just two of these quantities of material into perspective the amount of concrete used at Sooner would cover over seven football fields with concrete one foot thick and the electrical cable used would stretch from Oklahoma City to Tulsa and back with a few miles of cable left over.

In terms of personnel used to install these materials, the craft labor force peaked at over 700 workers and will have expended over 2,800,000 man-hours at completion of the thirty-one (31) month construction period. This does not include the man-hours used to fabricate and transport materials and equipment off site.

Q. **How do current cost estimates to install CDS on the Sooner units compare to the original project estimates?**

A. Originally, the Company estimated the cost to be $530 million plus or minus 10%, this estimate was based on direct cost, exclusive of AFUDC and Ad Valorem taxes. Currently, the Company's cost estimates are much less than the original estimate, OG&E expects the Sooner CDS project to be completed for approximately $450 million.

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

A. Present costs are significantly lower than the 2008 BART Evaluations. The 2009 BART estimates for dry FGD systems were approximately $390 Million per unit with wet FGD units estimated at $441 Million per unit.

Q. **How do the expected operating costs compare to original estimates?**

A. Operating costs are trending lower. Reagent lime is a large contributor to operating costs. Since the original estimate, lime usage rates and lime pricing have dropped significantly. The original estimate assumed that at a 70% capacity factor, lime costs would be $4,024,800 per year, that estimate is now $2,634,400 per year.

Waste disposal costs have also been reduced. The original estimate assumed disposing 53,000 tons per year at $ 58.66 per ton disposal cost for waste byproducts. Again, assuming a 70% capacity factor that was $ 3,112,500 per year. With lime usage being down waste volume is also down. Additionally, negotiated pricing on disposal also was secured at less than originally estimated. This yields an estimate of $1,525,500 per year as compared to an original estimate of $3,112,500 per year.

Overall, based on an assumed 70% capacity factor, the estimated operating costs have dropped by $2,977,400 per year.

Q. **What is the status of the CDS installation at Sooner?**

A. Unit 1 CDS has been tied in and operational since June 21, 2018 and was declared commercial on October 12, 2018. The unit is in service and removing SO_2 to contractual and permit levels. Tuning and optimization is ongoing and as of November 5, 2018 the unit has entered the contractual performance test period.

Unit 2 completed its tie in outage on October 28, 2018 with the unit returning to service on October 29, 2018. As of that date, commissioning of the CDS has been underway. The unit is expected to be commissioned and tuned such that it is in compliance with the RHR FIP prior to the RHR compliance date of January 4, 2019.

Q. **What are the next major milestones for the CDS installation at Sooner**?

A. The next major milestone for the Sooner CDS project will be to complete the performance testing on Unit 1 and to commission, tune/optimize and conduct performance testing on Unit 2. Optimization/Tuning as well as contractual performance testing on Unit 2 will extend into the first quarter of 2019. However, the unit is expected to be compliant with RHR SO_2 limits by the compliance date.

Q. When was Sooner Unit 1 CDS declared to be in commercial service?

A. Sooner Unit 1 was declared commercial on October 12, 2018.

Q. When does OG&E expect Sooner Unit 2 CDS to be in commercial service?

A. OG&E expects Sooner Unit 2 to be declared commercial in early January 2019.

Q. Will Sooner Unit 2 be in compliance by January 4, 2019 if it is not commercial until after that date?

A. It is expected that both Sooner units will be in compliance by the compliance date of January 4, 2019 as prescribed by the Regional Haze FIP, assuming no major startup and commissioning issues. While the unit will be in compliance by January 4, 2019 testing and tuning will continue to optimize performance and reagent usage and to verify vendor compliance with the contract.

Q. Please describe the equipment and processes involved with converting Muskogee Units 4 and 5 to natural gas.

A. The process of converting Muskogee Units 4 and 5 to burn natural gas in lieu of coal is a straightforward one. Coal pulverizing and conveying equipment will be retired and removed to the extent it does not impede natural gas operation or introduce any employee safety concerns, otherwise the equipment will be retired in place. The same philosophy will be applied to fly ash and bottom ash removal equipment. Once the coal equipment external to the boilers has been removed, the coal burners will also be removed. In their place will be a new configuration of natural gas burners and air registers necessary to support safe and efficient combustion of natural gas. The project will also involve piping and facilities to regulate and convey natural gas from the Suppliers custody transfer point to the boilers. Gas distribution piping at the burner front will be constructed as will the necessary piping and valving required to safely vent gas during start-up and shutdown events.

In addition, boiler control hardware and logic will be modified to support natural gas operation as opposed to coal operation.

An auxiliary boiler will also be constructed to provide the heating steam necessary to maintain the equipment in safe and reliable condition during cold weather events. The auxiliary boiler is needed as part of the conversion project because the expected utilization of the converted units is much less than when they were in coal service. During times of cold weather prior to conversion, there was a high likelihood that at least one other coal unit would be in service and available to provide necessary heating steam.

Q. **Please describe the project execution plan and contracting strategy for the Muskogee Conversion Project.**

A. Once the decision was made to convert to natural gas, OG&E hired Burns and McDonnell to develop performance and procurement specifications for the major areas of work. These areas include, burners and burner installation, auxiliary boiler supply, control hardware and re-configuration and general contracting. The General Contractor ("GC") would be responsible for the installation of the auxiliary boiler and auxiliary boiler systems, the connecting gas piping, any electrical work or relocations, and the rerouting or installation of any other balance of plant equipment or systems. Once the specifications were prepared, each specification was sent to several bidders for competitive bidding. Bids were accepted, evaluated and the number of bidders was narrowed to a short list, typically two or three vendors. Parallel negotiations were then conducted with each short list vendor, resulting in an award decision.

Q. Are there any other major areas of work associated with the Muskogee Units 4 and 5 conversion project?

A. Yes. Sufficient natural gas supply capacity is being installed. This consists of approximately 83 miles of high pressure, natural gas pipeline.

Q. **When is the gas line expected to be in service at Muskogee?**

A. The new gas line went into service on December 1, 2018.

Q. **How did OG&E select the Supplier for the natural gas?**

A. OG&E's Fuels group conducted a competitive bidding event to supply firm gas transmission service and facilities to the Muskogee plant. Enable Midstream was the successful bidder.

Q. **Is the cost of the gas line included in OG&E's current $72 Million cost estimate?**

A. No. Enable's recovery of the gas line costs is through a demand charge for gas transmission service. Since this cost is associated with fuel it appears as a Fuel Adjustment Clause cost.

Q. **What is the current status of the Muskogee conversion project?**

A. The project is in the construction phase with all major materials on site. Construction is on schedule to be complete on or before December 21, 2018

Q. **How do present cost estimates to convert Muskogee Units 4 and 5 to burn natural gas compare to originally discussed costs.**

A. Present cost estimates are trending slightly below the previously stated $72 million ($36 Million per unit, exclusive of AFUDC and Ad Valorem taxes) as discussed in the Company's 2014 ECP case.

Q **Was the cost of the gas line considered in the overall evaluation of this project.**

A. Yes. As best described by Witness Leon Howell, the cost of the gas line was considered in the economic evaluation of this project. Considering all costs, including the gas line, converting the Muskogee Units 4 and 5 to natural gas was the least cost option to maintain approximately 1,000 MWs of low cost capacity for OG&E customers.

Q. **What are the next major mile stones for the Muskogee Units 4 and 5 conversion project?**

A. The next major milestone for the Muskogee conversion project will be Mechanical Completion on or before December 21, 2018. Mechanical Completion will be followed by commissioning and testing and optimization. The unit is expected to return to commercial service in compliance with RHR in March of 2019.

Q. **When does OG&E expect the converted Muskogee units to be in commercial service?**

A. OG&E expects both of the converted Muskogee units to be in commercial service in March of 2019.

Q. **How will a March 2019 commercial service date allow the units to be compliant with a January 4, 2019 FIP compliance date for SO2 emissions.**

A Compliance with the SO_2 FIP is a 30-day rolling average compliance based on operating days. Since the level of SO_2 that will be emitted from a converted Muskogee unit will be significantly less than the 0.06 lb/MM BTU SO2 limit in the FIP OG&E does not expect any compliance issues once the units are converted and started up, even during testing and optimization. Expected lower SO_2 emissions are based on the significantly lower amount of sulfur in natural gas as compared to coal.

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. I have also explained the various technological options OG&E explored for complying with the SO_2 emission limits imposed on the Company through this rule and how the Company evaluated these options based on effectiveness, cost and timing. I then summarized the proposed plan resulting from our evaluation and provided 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 a lowest reasonable cost.

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

A. Yes.