Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis — January 15, 2010

COMPANY:	**Oklahoma Gas and Electric**
FACILITY:	**Muskogee Generating Station**
FACILITY LOCATION:	**Muskogee, Muskogee County, Oklahoma**
TYPE OF OPERATION:	**(2) 572 MW Steam Electric Generating Units**
REVIEWERS:	**Phillip Fielder, Senior Engineering Manager** **Lee Warden, Engineering Manager**

I. PURPOSE OF APPLICATION

On July 6, 2005, the U.S. Environmental Protection Agency (EPA) published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule" 70 FR 39104). The Regional Haze Rule requires certain States, including Oklahoma, to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The Regional Haze Rule requires states to submit a plan to implement the regional haze requirements (the Regional Haze SIP). The Regional Haze SIP must provide for a Best Available Retrofit Technology (BART) analysis of any existing stationary facility that might cause or contribute to impairment of visibility in a Class I Area.

II. BART ELIGIBILITY DETERMINATION

BART-eligible sources include those sources that:

(1) have the potential to emit 250 tons or more of a visibility-impairing air pollutant;
(2) were in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
(3) whose operations fall within one or more of the specifically listed source categories in 40 CFR 51.301 (including fossil-fuel fired steam electric plants of more than 250 mmBtu/hr heat input and fossil-fuel boilers of more than 250 mmBtu/hr heat input).

Muskogee Units 4 and 5 are fossil-fuel fired boilers with heat inputs greater than 250-mmBtu/hr. Both units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Based on a review of existing emissions data, both units have the potential to emit more than 250 tons per year of NO_X, SO_2, and PM_{10}, visibility impairing pollutants. Therefore, Muskogee Units 4 and 5 meet the definition of a BART-eligible source.

BART is required for any BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area.

DEQ has determined that an individual source will be considered to "contribute to visibility impairment" if emissions from the source result in a change in visibility, measured as a change in deciviews (Δ-dv), that is greater than or equal to 0.5 dv in a Class I area. Visibility impact modeling conducted by OG&E determined that the maximum predicted visibility impacts from Muskogee Units 4 and 5 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains, Caney Creek Upper Buffalo, and Hercules Glade Class I Areas. Therefore, Muskogee Units 4 and 5 were determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Muskogee Units 4 and 5 were developed based on an evaluation of actual emissions data submitted by the facility pursuant to the federal Acid Rain Program. In accordance with EPA guidelines in 40 CFR 51 Appendix Y Part III, emission estimates used in the modeling analysis to determine visibility impairment impacts should reflect steady-state operating conditions during periods of high capacity utilization. Therefore, modeled emissions (lb/hr) represent the highest 24-hour block emissions reported during the baseline period. Baseline emission rates (lb/mmBtu) were calculated by dividing the average annual mass emission rates for each boiler by the boiler's average heat input over the years 2004 through 2006.

Table 1: Muskogee Generating Station- Plant Operating Parameters for BART Evaluation

Parameter	**Muskogee Unit 4**		**Muskogee Unit 5**	
Plant Configuration	Pulverized Coal-Fired Boiler		Pulverized Coal-Fired Boiler	
Firing Configuration	Tangentially-fired		Tangentially-fired	
Gross Output (nominal)	572 MW		572 MW	
Maximum Input to Boiler	5,480 mmBtu/hr		5,480 mmBtu/hr	
2004-2006 Average Heat Input to Boiler	4,594 mmBtu/hr		4,739 mmBtu/hr	
Primary Fuel	Subbituminous coal		Subbituminous coal	
Existing NO_X Controls	Combustion controls		Combustion controls	
Existing PM_{10} Controls	Electrostatic precipitator		Electrostatic precipitator	
Existing SO_2 Controls	Low-sulfur coal		Low-sulfur coal	
Maximum 24-hour Emissions				
Pollutant	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	2,710	0.495	2,863	0.522
SO_2	4,384	0.800	4,657	0.850
PM_{10}	101	0.018	134	0.024
Baseline Emissions (2004- 2006)				
Pollutant	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	1,342	0.292	1,545	0.326
SO_2	2,329	0.507	2,436	0.514

IV. BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Guidelines for making BART determinations are included in Appendix Y of 40 CFR Part 51 (Guidelines for BART Determinations under the Regional Haze Rule). States are required to use the Appendix Y guidelines to make BART determinations for fossil-fuel-fired generating plants having a total generating capacity in excess of 750 MW. The BART determination process described in Appendix Y includes the following steps:

Step 1. Identify All Available Retrofit Control Technologies.
Step 2. Eliminate Technically Infeasible Options.
Step 3. Evaluate Control Effectiveness of Remaining Control Technologies.
Step 4. Evaluate Impacts and Document the Results.
Step 5. Evaluate Visibility Impacts.

In the final Regional Haze Rule U.S.EPA established presumptive BART emission limits for SO_2 and NO_X for certain electric generating units (EGUs) based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls. The presumptive limits apply to EGUs at power plants with a total generating capacity in excess of 750 MW. For these sources, EPA established presumptive emission limits for coal-fired EGUs greater than 200 MW in size. The presumptive levels are intended to reflect highly cost-effective technologies as well as provide enough flexibility to States to consider source specific characteristics when evaluating BART. The BART SO_2 presumptive emission limit for coal-fired EGUs greater than 200 MW in size without existing SO_2 control is either 95% SO_2 removal, or an emission rate of 0.15 lb/mmBtu, unless a State determines that an alternative control level is justified based on a careful consideration of the statutory factors. For NO_X, EPA established a set of BART presumptive emission limits for coal-fired EGUs greater than 200 MW in size based upon boiler size and coal type. The BART NO_X presumptive emission limit applicable to Muskogee Units 4 and 5 (tangentially fired boilers firing subbituminous coal) is 0.15 lb/mmBtu.

Table 2: BART Controls and Limits

Unit	**NO_X BART Emission Limit**	**BART Technology**
Muskogee Unit 4	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Muskogee Unit 5	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Unit	**SO_2 BART Emission Limit**	**BART Technology**
Muskogee Unit 4	0.65 lb/mmBtu (30-day average)	Low Sulfur Coal
	0.55 lb/mmBtu (annual average)	
Muskogee Unit 5	0.65 lb/mmBtu (30-day average)	Low Sulfur Coal
	0.55 lb/mmBtu (annual average)	
Units 4 and 5	18,096 TPY	Low Sulfur Coal
Unit	**PM_{10} BART Emission Limit**	**BART Technology**
Muskogee Unit 4	0.1 lb/mmBtu (3-hour average)	Electrostatic Precipitator
Muskogee Unit 5	0.1 lb/mmBtu (3-hour average)	Electrostatic Precipitator

A. NO_X

IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Potentially available control options were identified based on a comprehensive review of available information. NO_X control technologies with potential application to Muskogee Units 4 and 5 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Low NO_X Burners and Overfire Air (LNB/OFA)
Flue Gas Recirculation (FGR)
Post Combustion Controls
Selective Noncatalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Innovative Control Technologies
Rotating Overfire Air (ROFA)
ROFA + SNCR (Rotamix)
Pahlman Multi-Pollutant Control Process
Wet NO_X Scrubbing

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)

Combustion Controls:

Low NO_X burners (LNB)/ Over Fire Air (OFA)

Low NO_X burners (LNB) limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Over Fire Air (OFA) allows for staged combustion. Staging combustion reduces NO_X formation with a cooler flame in the initial stage and less oxygen in the second stage.

LNB/OFA emission control systems have been installed as retrofit control technologies on existing coal-fired boilers. Muskogee Units 4 and 5 operate as base load units. While technically feasible, LNB/OFA may not be as effective under all boiler operating conditions, especially during load changes and at low operating loads. Based on information available from burner control vendors and engineering judgment, it is expected that LNB/OFA on tangentially-fired boilers can be designed to meet the presumptive NO_X BART emission rate of 0.15 lb/mmBtu on a 30-day rolling average and under all normal operating conditions while maintaining acceptable CO and VOC emission rates.

Flue Gas Recirculation

Flue gas recirculation (FGR) controls NO_X by recycling a portion of the flue gas back into the primary combustion zone. The recycled air lowers NO_X emissions by two mechanisms: (1) the recycled gas, consisting of products which are inert during combustion, lowers the combustion temperatures; and (2) the recycled gas will reduce the oxygen content in the primary flame zone. The amount of recirculation is based on flame stability.

FGR control systems have been used as a retrofit NO_X control strategy on natural gas-fired boilers, but have not generally been considered as a retrofit control technology on coal-fired units. Natural gas-fired units tend to have lower O_2 concentrations in the flue gas and low particulate loading. In a coal-fired application, the FGR system would have to handle hot particulate-laden flue gas with a relatively high O_2 concentration. Although FGR has been used on coal-fired boilers for flue gas temperature control, it would not have application on a coal-fired boiler for NO_X control. Because of the flue gas characteristics (e.g., particulate loading and O2 concentration), FGR would not operate effectively as a NO_X control system on a coal-fired boiler. Therefore, FGR is not considered an applicable retrofit NO_X control option for Muskogee Units 4 and 5, and will not be considered further in the BART determination.

Post Combustion Controls:
Selective Non-Catalytic Reduction
Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia or urea at high flue gas temperatures. The ammonia or urea reacts with NO_X in the flue gas to produce N_2 and water. At temperatures below the desired operating range, the NO_X reduction reactions diminish and NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_X resulting in low NO_X reduction efficiencies. Mixing of the reactant and flue gas within the reaction zone is also an important factor in SNCR performance. In large boilers, the physical distance over which the reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, reducing overall efficiency. Performance is further influenced by residence time, reagent-to-NO_X ratio, and fuel sulfur content.

The size of the Muskogee Units would represent several design problems making it difficult to ensure that the reagent would be injected at the optimum flue gas temperature, and that there would be adequate mixing and residence time. The physical size of the Muskogee boilers makes it technically infeasible to locate and install ammonia injection points capable of achieving adequate mixing within the required temperature zone. Higher reagent injection rates would be required to achieve adequate mixing. Higher ammonia injection rates would result in relatively high levels of ammonia in the flue gas (ammonia slip), which could lead to plugging of downstream equipment.

Another design factor limiting the applicability of SNCR control systems on large subbituminous coal-fired boilers is related to the reflective nature of subbituminous ash. Subbituminous coals typically contain high levels of calcium oxide and magnesium oxide that can result in reflective ash deposits on the waterwall surfaces. Because most heat transfer in the furnace is radiant, reflective ash can result in less heat removal from the furnace and higher exit gas temperatures. If ammonia is injected above the appropriate temperature window, it can actually lead to additional NO_X formation.

Installation of SNCR on large boilers, such as those at Muskogee, has not been demonstrated in practice. Assuming that SNCR could be installed on the Muskogee Units, given the issues addressed above, control effectiveness would be marginal, and depending on boiler exit temperatures, could actually result in additional NO_X formation. SNCR is not a technically feasible retrofit control for the Muskogee Boilers.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NO_X to N2 and water. Anhydrous ammonia injection systems may be used, or ammonia may be generated on-site from a urea feedstock.

SCR has been installed as NO_X control technology on existing coal-fired boilers. Based on emissions data available from the EPA Electronic Reporting website, large coal-fired boilers have achieved actual long-term average NO_X emission rates in the range of approximately 0.04 to 0.1 lb/mmBtu. Several design and operating variables will influence the performance of the SCR system, including the volume, age and surface area of the catalyst (e.g., catalyst layers), uncontrolled NO_X emission rate, flue gas temperature, and catalyst activity.

Based on emission rates achieved in practice at existing subbituminous coal-fired units, and taking into consideration long-term operation of an SCR control system (including catalyst plugging and deactivation) it is anticipated that SCR could achieve a controlled NO_X emission rate of 0.07 lb/mmBtu (30-day rolling average) on Muskogee Units 4 and 5.

Innovative NO_X Control Technologies:

Rotating Opposed Fire Air and Rotomix

Rotating opposed fired air (ROFA) is a boosted over fire air system that includes a patented rotation process which includes asymmetrically placed air nozzles. Like other OFA systems, ROFA stages the primary combustion zone to burn overall rich, with excess air added higher in the furnace to burn out products of incomplete combustion.

ROFA and Rotamix® systems have been demonstrated on smaller coal-fired boilers but have not been demonstrated in practice on boilers similar in size to Muskogee Units 4 and 5. As discussed for OFA, over fire air control systems are a technically feasible retrofit control technology, and, based on engineering judgment, the ROFA design could also be applied on Muskogee Units 4 and 5. However, there is no technical basis to conclude that the ROFA design would provide additional NOX reduction beyond that achieved with other OFA designs. Therefore, ROFA control systems are not evaluated as a specific control system, but are included in the overall evaluation of combustion controls (e.g., LNB/OFA).

ROFA + SNCR (Rotamix)

The Rotamix system is a SNCR control system (i.e., ammonia injection system) coupled with the ROFA rotating injection nozzle design. The technical limitations discussed in the SNCR section, including the physical size of the boiler, inadequate NH3/NO_X contact, and flue gas temperatures, would apply equally to the Rotamix control system. There is no technical basis to conclude that the Rotamix design addresses these unresolved technical difficulties. Therefore, like other SNCR control systems, the Rotamix system is not a technically feasible retrofit control for the Muskogee Boilers.

Pahlman Multi-Pollutant Control Process

The Pahlman™ Process is a patented dry-mode multi-pollutant control system. The process uses a sorbent composed of oxides of manganese (the Pahlmanite™ sorbent) to remove NO_X and SO_2 from the flue gas.

To date, bench- and pilot-scale testing have been conducted to evaluate the technology on utility-sized boilers. The New & Emerging Environmental Technologies (NEET) Database identifies the development status of the Pahlman Process as full-scale development and testing. The process is an emerging multi-pollutant control, and there is limited information available to evaluate its technically feasibility and long-term effectiveness on a large natural gas-fired boiler. It is likely that OG&E would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system on Muskogee Units 4 and 5. BART does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time the Pahlman Process is not a technically feasible retrofit control for the Muskogee Boilers

Wet NO_X Scrubbing Systems

Wet scrubbing systems have been used to remove NO_X emissions from fluid catalytic cracking units (FCCUs) at petroleum refineries. An example of a wet scrubbing system is Balco Technologies' LoTOx™ system. The LoTOx system is a patented process, wherein ozone is injected into the flue gas stream to oxidize NO and NO_2 to N_2O_5. This highly oxidized species of NO_X is very soluble and rapidly reacts with water to form nitric acid. The conversion of NO_X to nitric acid occurs as the N_2O_5 contacts liquid sprays in the scrubber.

Wet scrubbing systems have been installed at chemical processing plants and smaller coal-fired boilers. The NEET Database classifies wet scrubbing systems as commercially established for petroleum refining and oil/natural gas production. However the technology has not been demonstrated on large utility boilers and it is likely that OG&E would incur substantial engineering and testing to evaluate the scale-up potential and long-term effectiveness of the system. Therefore, at this time wet NO_X scrubbing systems are not technically feasible retrofit controls for the Muskogee Boilers

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Muskogee Station

Control Technology	Muskogee Unit 4 Approximate NO_X Emission Rate (lb/mmBtu)	Muskogee Unit 5 Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.07	0.07
LNB/OFA	0.15	0.15
Baseline	0.292	0.326

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

OG&E evaluated the economic, environmental, and energy impacts associated with the two proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Major equipment costs were developed based on publicly available cost data and equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit

Muskogee Units 4 and 5 with the control technologies. Fixed and variable O&M costs were developed for each control system. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (e.g., ammonia), byproduct management, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with operation of the new control technology, including operation of any new fans as well as the power requirements for pumps, reagent handling, and by-product handling. The capital recovery factor used to estimate the annual cost of control was based on a 7% interest rate and a control life of 25 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 90%.

OG&E submitted initial cost estimates in 2008 that relied upon a baseline emission rate representative of the maximum actual 24-hour emission rate, which is consistent with the modeling demonstration. However, the calculations overestimate the cost effectiveness by assuming a larger ton per year emissions reduction with the addition of controls than would be realized given actual annual average emissions. Using a representative annual average emission rate (2004-2006), the cost effectiveness ($/ton removed) is much higher, but the result is representative of more reasonably achievable emissions reductions.

Table 5: Economic Cost Per Boiler

Cost	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR
Control Equipment Capital Cost ($)	$14,113,700	$193,077,000
Annualized Capital Cost ($/Yr)	$1,211,100	$16,568,000
Annual O&M Costs ($/Yr)	$880,700	$14,227,600
Annual Cost of Control ($)	$2,091,800	$30,795,600

Table 6: Environmental Costs per Boiler

		Baseline	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu)	Unit 4	0.292	0.15	0.07
	Unit 5	0.326	0.15	0.07
Annual NO_X Emission (TPY)[1]	Unit 4	5,258	2,674	1,246
	Unit 5	5,709	2,628	1,227
Annual NO_X Reduction (TPY)	Unit 4	--	2,587	4,012
	Unit 5	--	3,081	4,482
Annual Cost of Control	Unit 4	--	$2,091,800	$30,795,600
	Unit 5	--	$2,091,800	$30,795,600
Cost per Ton of Reduction	Unit 4	--	$809	$7,676
	Unit 5	--	$679	$6,871
Incremental Cost per ton of Reduction[2]	Unit 4	--	--	$20,143
	Unit 5	--	--	$20,488

(1) Emissions for the BART analysis are based on average heat inputs of 4,594 and 4,739 mmBtu/hr for Units 4 & 5. Annual emissions were calculated assuming 7,829 and 7,395 hours/year per for Units 4 and 5 respectively.

(2) Incremental cost effectiveness of the SCR system is compared to costs/emissions associated with LNB/OFA controls.

B. SO_2

IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES (SO_2)

Potentially available control options were identified based on a comprehensive review of available information. SO_2 control technologies with potential application to Muskogee Units 4 and 5 are listed in Table 7.

Table 7: List of Potential Control Options

Control Technology
Pre-Combustion Controls
Fuel Switching
Coal Washing
Coal Processing
Post Combustion Controls
Wet Flue Gas Desulfurization
Wet Lime FGD
Wet Limestone FGD
Wet Magnesium Enhanced Lime FGD
Jet Bubbling Reactor FGD
Dual Alkali Scrubber
Wet FGD with Wet Electrostatic Precipitator
Dry Flue Gas Desulfurization
Spray Dryer Absorber
Dry Sorbent Injection
Circulating Dry Scrubber

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (SO_2)

Pre-Combustion Control Strategy:

Fuel Switching

One potential strategy for reducing SO_2 emissions is reducing the amount of sulfur contained in the coal. Muskogee Units 4 and 5 fire subbituminous coal as their primary fuel. Subbituminous coal has a relatively low heating value, low sulfur content, and low uncontrolled SO_2 emission rate. No environmental benefits accrue from burning an alternative coal; therefore, fuel switching is not considered a feasible option for this retrofit project.

Coal Washing

Coal washing, or beneficiation, 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. The coal washing process generates a solid waste stream consisting of inorganic materials separated from the coal, and a wastewater stream that must be treated prior to discharge. Solids generated from wastewater processing and coarse material removed in the washing process must be disposed in a properly permitted landfill. Solid wastes from coal washing typically contain pyrites and other dense inorganic impurities including silica and trace metals. The solids are typically dewatered in a mechanical dewatering device and disposed of in a landfill.

Muskogee Units 4 and 5 are designed to utilize subbituminous coals. Based on a review of available information, no information was identified regarding the washability or effectiveness of washing subbituminous coals. Therefore, coal washing is not considered an available retrofit control option for Muskogee Units 4 and 5.

Coal Processing

Pre-combustion coal processing techniques have been proposed as one strategy to reduce the sulfur content of coal and help reduce uncontrolled SO_2 emissions. Coal processing technologies are being developed to remove potential contaminants from the coal prior to use. These processes typically employ both mechanical and thermal means to increase the quality of subbituminous coal and lignite by removing moisture, sulfur, mercury, and heavy metals. To date, the use of processed fuels has only been demonstrated with test burns in a pulverized coal-fired boiler. No coal-fired boilers have utilized processed fuels as their primary fuel source on an on-going, long-term basis. Although burning processed fuels, or a blend of processed fuels, has been tested in a pulverized coal-fired boiler, using processed fuels in Muskogee Units 4 and 5 would require significant research, test burns, and extended trials to identify potential impacts on plant systems, including the boiler, material handling, and emission control systems. Therefore, processed fuels are not considered commercially available, and will not be analyzed further in this BART analysis.

Post-Combustion Flue Gas Desulfurization:

Wet Scrubbing Systems

Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems offered by vendors may vary in design; however, all wet scrubbing systems utilize an alkaline scrubber slurry to remove SO_2 from the flue gas.

<u>*Wet Lime Scrubbing*</u>

The wet lime scrubbing process uses an alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed in the absorber and reacts with SO2 in the flue gas. Insoluble $CaSO_3$ and $CaSO_4$ salts are formed in the chemical reaction that occurs in the scrubber and are removed as a solid waste by-product. The waste by-product is made up of mainly $CaSO_3$, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills.

<u>*Wet Limestone Scrubbing*</u>

Limestone scrubbers are very similar to lime scrubbers except limestone ($CaCO_3$) is mixed with water to formulate the alkali scrubber slurry. SO_2 in the flue gas reacts with the limestone slurry to form insoluble $CaSO_3$ and $CaSO_4$ which is removed as a solid waste by product. The use of limestone instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed.

Forced oxidation of the scrubber slurry can be used with either the lime or limestone wet FGD system to produce gypsum solids instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite ($CaSO_3$) to relatively pure gypsum (calcium sulfate). Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the FGD. The gypsum by-product from this process must be dewatered, but may be salable thus reducing the quantity of solid waste that needs to be landfilled.

Wet lime and wet limestone scrubbing systems will achieve the same SO_2 control efficiencies; however, the higher cost of lime typically makes wet limestone scrubbing the more attractive option. For this reason, wet lime scrubbing will not be evaluated further in this BART determination.

Wet Magnesium Enhanced Lime Scrubbing
Magnesium Enhanced Lime (MEL) scrubbers are another variation of wet FGD technology. Magnesium enhanced lime typically contains 3% to 7% magnesium oxide (MgO) and 90 – 95% calcium oxide (CaO). The presence of magnesium effectively increases the dissolved alkalinity, and consequently makes SO_2 removal less dependent on the dissolution of the lime/limestone. MEL scrubbers have been installed on coal-fired utility boilers located in the Ohio River Valley. Systems to oxidize the MEL solids to produce a usable gypsum byproduct consisting of calcium sulfate (gypsum) and magnesium sulfate continue to be developed. Coal-fired units equipped with MEL FGD typically fire high-sulfur eastern bituminous coal and use locally available reagent. There are no subbituminous-fired units equipped with a MEL-FGD system. Because MEL-FGD systems have not been used on subbituminous-fired boilers, and because of the cost and limited availability of magnesium enhanced reagent (either naturally occurring or blended), and because limestone-based wet FGD control systems can be designed to achieve the same control efficiencies as the magnesium enhanced systems, MEL-FGD control systems will not be evaluated further as a commercially available retrofitted control system.

Jet Bubbling Reactor
Another variation of the wet FGD control system is the jet bubbling reactor (JBR). Unlike the spray tower wet FGD systems, where the scrubbing slurry contacts the flue gas in a countercurrent reaction tower, in the JBR-FGD flue gas is bubbled through a limestone slurry. Spargers are used to create turbulence within the reaction tank and maximize contact between the flue gas bubbles and scrubbing slurry. There is currently a limited number of commercially operating JBR-WFGD control systems installed on coal-fired utility units in the U.S. Although the commercial deployment of the control system continues, there is still a very limited number of operating units in the U.S. Furthermore, coal-fired boilers currently considering the JBR-WFGD control system are all located in the eastern U.S., and all fire eastern bituminous coals. The control system has not been proposed as a retrofit technology on any large subbituminous coal-fired boilers. However, other than scale-up issues, there do not appear to be any overriding technical issues that would exclude application of the control technology on a large subbituminous coal-fired unit. There are no data available to conclude that the JBR-WFGD control system will achieve a higher SO_2 removal efficiency than a more traditional spray tower WFGD design, especially on units firing low-sulfur subbituminous coal. Furthermore, the costs associated with JBR-WFGD and the control efficiencies achievable with JBR-WFGD are similar to the costs and control efficiencies achievable with spray tower WFGD control systems. Therefore, the JBR-WFGD will not be evaluated as a unique retrofit technology, but will be included in the overall assessment of WFGD controls.

Dual-Alkali Wet Scrubber

Dual-alkali scrubbing is a desulfurization process that uses a sodium-based alkali solution to remove SO_2 from combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The dual-alkali process requires lower liquid-to-gas ratios then scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units, however additional regeneration and sludge processing equipment is necessary. The sodium-based scrubbing liquor, typically consisting of a mixture of sodium hydroxide, sodium carbonate and sodium sulfite, is an efficient SO_2 control reagent. However, the high cost of the sodium-based chemicals limits the feasibility of such a unit on a large utility boiler. In addition, the process generates a less stable sludge that can create material handling and disposal problems. It is projected that a dual-alkali system could be designed to achieve SO_2 control similar to a limestone-based wet FGD. However, because of the limitations discussed above, and because dual-alkali systems are not currently commercially available, dual-alkali scrubbing systems will not be addressed further in this BART determination.

Wet FGD with Wet Electrostatic Precipitator

Wet electrostatic precipitation (WESP) has been proposed on other coal-fired projects as one technology to reduce sulfuric acid mist emissions from coal-fired boilers. WESPs have been proposed for boilers firing high-sulfur eastern bituminous coals controlled with wet FGD.24 WESP has not been widely used in utility applications, and has only been proposed on boilers firing high sulfur coals and equipped with SCR. Muskogee Units 4 and 5 fire low-sulfur subbituminous coal. Based on the fuel characteristics, and assuming 1% SO_2 to SO_3 conversion in the boiler, potential uncontrolled H_2SO_4 emissions from Muskogee Units 4 and 5 will only be approximately 5ppm. This emission rate does not take into account inherent acid gas removal associated with alkalinity in the subbiuminous coal fly ash. Based on engineering judgment, it is unlikely that a WESP control system would be needed to mitigate visible sulfuric acid mist emissions from Muskogee Units 4 and 5, even if WFGD control was installed. WESPs have been proposed to control condensable particulate emissions from boilers firing a high-sulfur bituminous coal and equipped with SCR and wet FGD; this combination of coal and control equipment results in relatively high concentrations of sulfuric acid mist in the flue gas. WESP control systems have not been proposed on units firing subbituminous coals, and WESP would have no practical application on a subbituminous-fired units. Therefore, the combination of WFGD+WESP will not be evaluated further in this BART determination.

Dry Flue Gas Desulfurization

Another scrubbing system that has been designed to remove SO_2 from coal-fired combustion gases is dry scrubbing. 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 FGD systems that produce a slurry byproduct that is collected separately from the fly ash, dry FGD systems produce a dry byproduct that must be removed with the fly ash in the particulate control equipment. Therefore, dry FGD systems must be located upstream of the particulate control device to remove the reaction products and excess reactant material.

Spray Dryer Absorber

Spray dryer absorber (SDA) systems have been used in large coal-fired utility applications. SDA systems have demonstrated the ability to effectively reduce uncontrolled SO_2 emissions from pulverized coal units. The typical spray dryer absorber uses a slurry of lime and water injected into the tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a relatively dry by-product. SDA control systems are a technically feasible and commercially available retrofit technology for Muskogee Units 4 and 5. Based on the fuel characteristics and allowing a reasonable margin to account for normal operating conditions (e.g., load changes, changes in fuel characteristics, reactant purity, atomizer change outs, and minor equipment upsets) it is concluded that dry FGD designed as SDA could achieve a controlled SO_2 emission rate of 0.10 lb/mmBtu (30-day average) on an on-going long-term basis.

Dry Sorbent Injection

Dry sorbent injection involves the injection of powdered absorbent directly into the flue gas exhaust stream. Particulates generated in the reaction are controlled in the system's particulate control device. Typical SO_2 control efficiencies for a dry sorbent injection system are generally around 50%. OG&E stated that because the control efficiency of the dry sorbent system is lower than the control efficiency of either the wet FGD or SDA, the system will not be evaluated further. As OG&E proposed only the use of low sulfur coal as BART, it is not clear why they did not include this technology in the full evaluation. Lacking any data to justify why this might be a more cost effective option than Dry FGD with SDA, this option is set aside based solely on lower environmental benefit.

Circulating Dry Scrubber

A third type of dry scrubbing system is the circulating dry scrubber (CDS). A CDS system uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. The dry by-product produced by this system is similar to the spray dry absorber by-product, and is routed with the flue gas to the particulate removal system. Operating experience on smaller pulverized coal boilers in the U.S. has shown high lime consumption rates, and significant fluctuations in lime utilization based on inlet SO_2 loading. Furthermore, CDS systems result in high particulate loading to the unit's particulate control device. Based on the limited application of CDS dry scrubbing systems on large boilers, it is likely that OG&E would be required to conduct extensive design engineering to scale up the technology for boilers the size of Muskogee Units 4 and 5, and that OG&E would incur significant time and resource penalties evaluating the technical feasibility and long-term effectiveness of the control system. Because of these limitations, CDS dry scrubbing systems are not currently commercially available as a retrofit control technology for Muskogee Units 4 and 5, and will not be evaluated further in this BART determination.

EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (SO_2)

Table 8: Technically Feasible SO_2 Control Technologies- Muskogee Station

Control Technology	Muskogee Unit 4 Approximate SO_2 Emission Rate (lb/mmBtu)	Muskogee Unit 5 Approximate SO_2 Emission Rate (lb/mmBtu)
Wet FGD	0.08	0.08
Dry FGD- Spray Dryer Absorber	0.10	0.10
Modeling Baseline	0.80	0.85
Annual Average Baseline	0.507	0.514

EVALUATE IMPACTS AND DOCUMENT RESULTS (SO_2)

Capital Costs

In 2008 OG&E evaluated the economic, environmental, and energy impacts associated with the two proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Sixth Edition" EPA-452/B-02-001, January 2002. The cost-effectiveness evaluations were "study" estimates of ±30% accuracy, based on: (1) engineering estimates; (2) vendor quotations provided for similar projects and similar equipment; (2) S&L's internal cost database; and (4) cost estimating guidelines provided in U.S.EPA's, EPA Air Pollution Control Cost Manual. Cost estimates include the equipment, material, labor, and all other direct costs needed to retrofit Muskogee Units 4 and 5 with the control technologies.

While generally following the EPA methodology, these cost estimates exploited weaknesses in the estimate assumptions and resulted in highly exaggerated capital and particularly annual costs. In response to the ODEQ draft evaluation and EPA and FLM comments, OG&E submitted revised cost estimates during the public meeting held for the Oklahoma draft SIP. These revised estimates reflect vendor quotes for the Muskogee facility. In degree of difficulty, the retrofit at the Muskogee facility is described as average. The re-routing of ductwork, storm sewer systems and other equipment relocations were taken into consideration in the conceptual cost estimate.

The new cost estimates use the following methodology:

- Plant design data were used to develop datasheets to specify the dry FGD, baghouse, and ID booster fan operating conditions. The datasheets were issued to various manufacturers to obtain budgetary quotations. Cost obtained from these quotations were used to derive the pricing used in the capital cost estimate.
- A general arrangement (GA) drawing was developed using the information received in the budgetary quotations. The GA drawing was used to estimate the major installation quantities for the project including ductwork, structural steel, foundations, relocation cable, and pipelines.
- A motor list was assembled and used to develop the auxiliary power system sizing and quantities.
- Mass balances were prepared and used to size the flue gas, material handling, material storage, and piping systems.

- A schedule was developed to estimate escalation and Allowance for Funds Used During Construction (AFUDC) costs. It was assumed the new DFGDs would come on line at six month intervals with the last unit being completed at Muskogee near the end of 2015.
- Range estimating techniques were used to identify the appropriate amount of contingency to obtain 95% confidence level. The contingency level was approximately 14%.
- A design and cost basis document was prepared to document the major assumptions and inputs for developing the cost estimate.
- Labor cost estimates were developed using the Oklahoma area wage rates, installation quantities, and installation rates taken from the Sargent and Lundy database.

The described methodology provides a conceptual capital cost estimate with accuracy in the range of ±20%. This methodology provides a better estimate of the capital costs associated with installing DFGD control systems, and a more accurate estimate of the actual costs that OG&E would incur to install DFGD at the Muskogee facility.

The total capital requirement (TCR) is the sum of direct costs, indirect costs, contingency, escalation, and AFUDC. Direct costs include equipment, material, labor, spare parts, special tools, consumables, and freight. Indirect costs include engineering, procurement, construction management, start-up, commissioning, operator training, and owner's costs.

Escalation and AFUDC were calculated from the estimated distribution of cash flows during the construction period and OG&E's before-tax weighted average cost of capital of 8.66% /year. The 37-day tie-in outage for each unit is assumed to be coordinated with the normal 5-week scheduled outage such that incremental replacement cost is negligible.

The capital recovery factor converts the TCR into equal annual costs over the depreciable life of the asset. These are also referred to as levelized capital charges. Property taxes and insurance are sometimes included with the capital charges, but are classified in the OG&E analysis as part of the Indirect Operating Costs to be consistent with the BART reports. The economic parameters used to derive the levelized capital charges are summarized in Table 9.

Table 9: Economic Parameters to Derive Levelized Capital Charges

Commercial Operation Date (Reference Year)	2015
Depreciable Life	20 years
Inflation Rate	2.5% /year
Effective Income Tax Rate- Federal and State	38.12%
Common Equity Fraction	0.557
Debt Fraction	0.443
Return on Common Equity	
Nominal	10.75% /year
Real	8.05% /year
Return on Debt	
Nominal	6.03% /year

Real	3.44% /year
Discount Rate (after-tax cost of capital)	
Nominal	7.64% /year
Real	5.43% /year
Tax Depreciation	20-year straight line
Levelized Capital Charges (real)	**10.36% /year**

The revised estimates based on vendor quotes results in a TCR of $634,386,800 which is $111,825,200 less than the CUECost derived estimates provided in 2008. However, OG&E has revised the capital recovery factor and reduced the number of years of expected depreciation to 20 from 25 resulting in a levelized capital charge or capital recovery of 32,861,300 per boiler, which is $844,900 per boiler per year more than the 2008 estimate. Cost estimates and assumptions are reasonable and application of the previously relied upon capital recovery factor does not significantly change the cost per ton of control or the conclusion of this review.

Operating Costs

Annual operating costs for the DFGD system consist of variable operating and maintenance (O&M) costs, fixed O&M costs, and indirect operating costs.

Variable O&M

Variable O&M costs are items that generally vary in proportion to the plant capacity factor. These consist of lime reagent costs, water costs, FGD waste disposal costs, bag and cage replacement costs, ash disposal costs, and auxiliary power costs.

Lime Reagent costs were based on material balances and budgetary lime quotations received for truck delivery, $105.53/ton, which is 52% of the previously assumed cost. Water costs were based on 219,839 lb/hr at full load, a 90% capacity factor and $2.57/1000 gallons. FGD Waste Disposal was based on material balances for the average fuel composition and a 90% capacity factor. First year cost of on-site disposal is $40.59/ton. Bag and cage replacement costs were based on exhaust gas flow through the baghouse, an air-to-cloth ratio of 3.5 for pulse jet baghouse, 4% contingency for bag cleaning, and 3-year bag life. The first year bag cost (including fabric and hangers) is $\$3.31/ft^2$. Ash disposal costs were not assumed to increase from the fabric filter as existing ESP is remaining in service. Auxiliary power costs were based on auxiliary power calculations and a 90% capacity factor. The first year auxiliary power cost is $85.92/MWh, which is 180% of the previously assumed power cost.

Increases in water, FGD waste disposal, bag and cage replacement, and auxiliary power costs offset decreases in lime reagent costs resulting in an increase in expected variable O&M costs from the 2008 estimate by approximately $1,000,000 per boiler per year.

Fixed O&M

Fixed O&M costs are recurring annual costs that are generally independent of the plant capacity factor. Theses consist of operating labor, supervisor labor, maintenance materials, and maintenance labor.

Operating labor was based on three shifts per day 365 days per year. The first year labor rate (salary plus benefits) is 58.76/hour. Supervisory labor was based on 15% of operating labor in accordance with the EPA Control Cost Manual (page 2-31). Maintenance materials were based on 0.6% of the total plant investment. Previous cost estimates reflecting Cue Cost default assumptions were based on 5% of capital equipment costs and therefore contributed to the exaggeration of annual operating costs. Maintenance labor was again based on 110% of operating labor, which is consistent with the EPA Control Cost Manual (page 2-31).

Due to the difference in cost basis for maintenance materials, the final fixed O&M costs were decreased by approximately $10,300,000 per year per boiler.

Indirect Operating Costs

Indirect operating costs are recurring annual costs for the FGD system that are not part of the direct O&M. These consist of property taxes, insurance, and administration.

Property taxes were calculated as 0.85% of total capital investment, in accordance with OG&E property tax rates. This rate is significantly lower than the EPA default rate of 1%. Insurance rates were calculated as 0.0105% of total capital investment in accordance with OG&E insurance rates. This rate is significantly lower than the EPA default rate of 1%. Administrative costs were calculated as 20% of the fixed O&M costs rather the EPA Air Pollution Control Cost Manual 6th Ed guidance of 2% of capital investment.

Due to the difference in cost basis for all indirect costs, but most particularly administrative costs, the final indirect operating costs were decreased by approximately $10,980,000 per year per boiler from the previous assessment.

Revised O&M estimates are now consistent with the operating costs documented in the June 2007 report by J. Edward Cichanowicz for the Utility Air Regulatory Group, "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies. The Cichanowicz report lists a cost range in $/kW of 15 to 38 for O&M costs. OG&E estimates are approximately $29-32/kW.

OG&E submitted initial cost estimates in 2008 that relied upon a baseline emission rate representative of the maximum actual 24-hour emission rate, which is consistent with the modeling demonstration. Following the methodology published in the EPA advanced notice of proposed rulemaking for the Four Corners Power Plant and the Navajo Generating Station, cost effectiveness calculations were revised to reflect average annual emissions from 2004-2006.

Table 10: Economic Cost for Units 4 and 5 - Dry FGD- Spray Dryer Absorber

Cost	Unit 4	Unit 5
Total Capital Investment ($)	$317,193,600	$317,193,600
Total Capital Investment ($/kW)	$555	$555
Capital Recovery Cost ($/Yr)	$32,861,300	$32,861,300
Annual O&M Costs ($/Yr)	$18,438,900	$18,438,900
Total Annual Cost ($)	$51,300,200	$51,300,200

Table 11: Environmental Costs for Units 4 and 5- Dry FGD- Spray Dryer Absorber

	Unit 4	Unit 5
SO_2 Baseline (TPY) [1]	9,113	9,006
SO_2 Controlled (lb/mmBtu)	0.1	0.1
Annual SO_2 Controlled (TPY)[2]	2,160	2,160
Annual SO_2 Reduction (TPY)	6,953	6,846
Total Annual Cost ($)	$51,300,200	$51,300,200
Cost per Ton of Reduction	$7,378	$7,493

(1) Baseline annual emissions are calculated as the average actual SO_2 emission rate during the baseline years of 2004-2006.
(2)Projected annual emissions were calculated based on the controlled SO_2 emissions rate, full load heat input of 5,480 mmBtu/hr, and assuming 7,884 hours/year per boiler (90% capacity factor).

OG&E did not submit revised cost estimates for Wet FGD; however, in order to be thorough, some conclusions can be drawn from the estimates provided for Dry FGD. The total capital requirement for wet scrubbers was assumed to be consistent with the previous determination. The capital recovery factor was modified to reflect the current company position of a 20 year depreciation. The annual operating costs were modified to reflect the cost bases for water, labor, auxiliary power, taxes, insurance and administrative costs detailed in the preceding paragraphs.

Table 12: Environmental Costs for Unit 4 or 5- Wet FGD

	OG&E Cost Estimates	
Cost	Unit 4	Unit 5
Total Capital Investment ($)	$418,567,000	$418,567,000
Capital Recovery Cost ($/Yr)	$43,363,541	$43,363,541
Annual O&M Costs ($/Yr)	$21,061,140	$21,061,140
Total Annual Cost ($)	$64,424,681	$64,424,681
Control SO_2 Emission Rate (lb/mmBtu)	0.08	0.08
Baseline Annual Emissions (TPY)[1]	9,113	9,006
Controlled Annual SO_2 Emission (TPY)[2]	1,728	1,728
Annual SO_2 Reduction (TPY)	7,385	7,278
Cost per Ton of Reduction ($/Ton)	$8,724	$8,852
Incremental Annual Cost ($/Ton)	$30,381	$30,381

(1) Baseline annual emissions were calculated based on average annual SO_2 emissions for the years 2004-2006.
(2)Projected annual emissions were calculated based on the controlled SO_2 emissions rate, full load heat input of 5,480 mmBtu/hr, and assuming 7,884 hours/year per boiler (90% capacity factor).

C. PM_{10}

IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES (PM_{10})

There are two generally recognized PM control devices that are used to control PM emission from PC boilers: ESPs and fabric filters (or baghouses). Muskogee Units 4 and 5 are currently equipped with ESP control systems.

Table 13: Summary of Technically Feasible Main Boiler PM_{10} Control Technologies

Control Technology	PM10 Emissions[1] lb/mmBtu)	% Reduction (from base case)
Fabric Filter Baghouse	0.015	99.7
ESP - Existing	0.025	99.3
Potential PM Emissions	5.65	-

[1] The PM_{10} emission rate for the baghouse case is based on filterable PM_{10} emission limits included in recently issued PSD permits for new coal-fired units. The PM_{10} emission rate for the ESP case is based on the Units' baseline PM_{10} emission rates. Potential PM emissions were calculated assuming an average fuel heating value of 8,500 Btu/lb and an ash content of 6.0%, and assuming 80% of the fuel ash will be emitted as fly ash.

EVALUATE IMPACTS AND DOCUMENT RESULTS (PM_{10})

Costs for Fabric Filter Baghouses were included in the cost estimates provided by OG&E for Dry FGD. Because of the interdependency of the control systems, a determination of baghouse versus existing ESP cannot be made without consideration of the eventual sulfur control. Annual average PM emissions are less than 500 TPY for both boilers. On a PM basis alone and assuming the current 20 year depreciation, no additional operating costs, and 100% emission reduction, a resultant cost effectiveness of $9,324 per ton would support the conclusion that further reductions from the addition of a $45,000,000 fabric filter are not cost effective.

D. VISIBILITY IMPROVEMENT DETERMINATION

The fifth of five factors that must be considered for a BART determination analysis, as required by a 40 CFR part 51- Appendix Y, is the degree of Class I area visibility improvement that would result from the installation of the various options for control technology. This factor was evaluated for the Muskogee Generating Station by using an EPA-approved dispersion modeling system (CALPUFF) to predict the change in Class I area visibility. The Division had previously determined that the Muskogee Generating Station was subject to BART based on the results of initial screening modeling that was conducted using current (baseline) emissions from the facility. The screening modeling, as well as more refined modeling conducted by the applicant, is described in detail below.

Wichita Mountain Wildlife Refuge, Caney Creek, Upper Buffalo and Hercules Glade are the closest Class I areas to the Muskogee Generating Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Muskogee Generating Station were modeled, as determined by source/Class I area locations, distances to each Class I area, and professional judgment considering meteorological and terrain factors. It can be reasonably assumed that areas at greater distances and in directions of less frequent plume transport will experience lower impacts than those predicted for the four modeled areas.

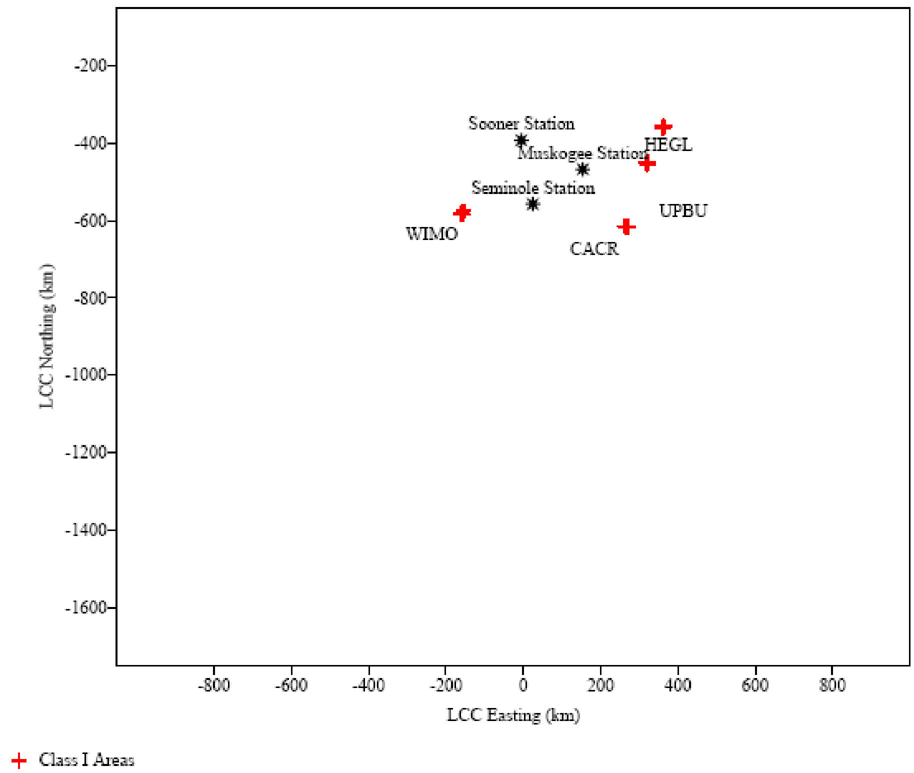

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING

Because of the results of the applicants screening modeling for the Muskogee Generating Station, OG&E was required to conduct a refined BART analysis that included CALPUFF visibility modeling for the facility. The modeling approach followed the requirements described in the Division's BART modeling protocol, CENRAP BART Modeling Guidelines (Alpine Geophysics, December 2005) with refinements detailed the applicants CALMET modeling protocol, CALMET Data Processing Protocol (Trinity Consultants, January 2008)

CALPUFF System

Predicted visibility impacts from the Muskogee Generating Station were determined with the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport. As described in the EPA Guideline on Air Quality Models (Appendix W of 40 CFR Part 51), long-range transport is defined as modeling with source-receptor distances greater than 50 km. Because all modeled areas are located more than 50 km from the sources in question, the CALPUFF system was appropriate to use.

The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF model was developed as a non-steady-state air quality modeling system for assessing the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal.

CALMET is a diagnostic wind model that develops hourly wind and temperature fields in a three-dimensional, gridded modeling domain. Meteorological inputs to CALMET can include surface and upper-air observations from multiple meteorological monitoring stations. Additionally, the CALMET model can utilize gridded analysis fields from various mesoscale models such as MM5 to better represent regional wind flows and complex terrain circulations. Associated two-dimensional fields such as mixing height, land use, and surface roughness are included in the input to the CALMET model. The CALMET model allows the user to "weight" various terrain influences parameters in the vertical and horizontal directions by defining the radius of influence for surface and upper-air stations.

CALPUFF is a multi-layer, Lagrangian puff dispersion model. CALPUFF can be driven by the three-dimensional wind fields developed by the CALMET model (refined mode), or by data from a single surface and upper-air station in a format consistent with the meteorological files used to drive steady-state dispersion models. All far-field modeling assessments described here were completed using the CALPUFF model in a refined mode.

CALPOST is a post-processing program that can read the CALPUFF output files, and calculate the impacts to visibility.

All of the refined CALPUFF modeling was conducted with the version of the CALPUFF system that was recognized as the EPA-approved release at the time of the application submittal. Version designations of the key programs are listed in the table below.

Table 14: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.6394	070622

Meteorological Data Processing (CALMET)

As required by the Division's modeling protocol, the CALMET model was used to construct the initial three-dimensional wind field using data from the MM5 model. Surface and upper-air data were also input to CALMET to adjust the initial wind field.

The following table lists the key user-defined CALMET settings that were selected.

Table 15: CALMET Variables

Variable	Description	Value
PMAP	Map projection	LCC (Lambert Conformal Conic)
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	12
ZFACE	Cell face heights (m)	0, 20, 40, 60, 80, 100, 150, 200, 250, 500,

Variable	Description	Value
		1000, 2000, 3500
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model outputs	14 km (MM5 data)
RMAX1	Maximum radius of influence (surface layer, km)	20 km
RMAX2	Maximum radius of influence (layers aloft, km)	50 km
TERRAD	Radius of influence for terrain (km)	10 km
R1	Relative weighting of first guess wind field and observation (km)	10 km
R2	Relative weighting aloft (km)	25 km

The locations of the upper air stations with respect to the modeling domain are shown in Figure 2.

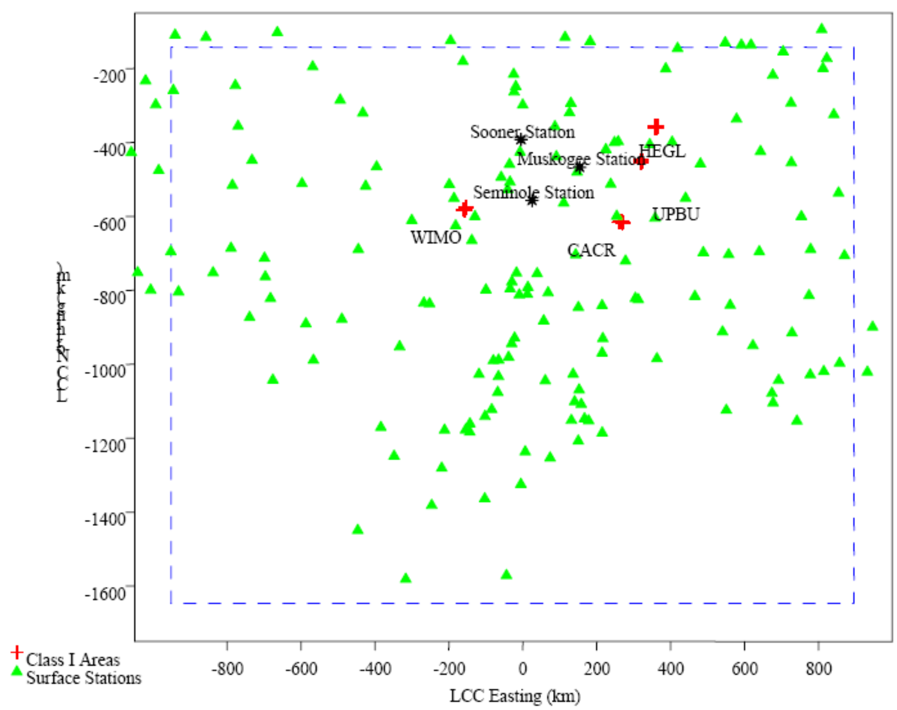

Figure 2: Plot of surface station locations

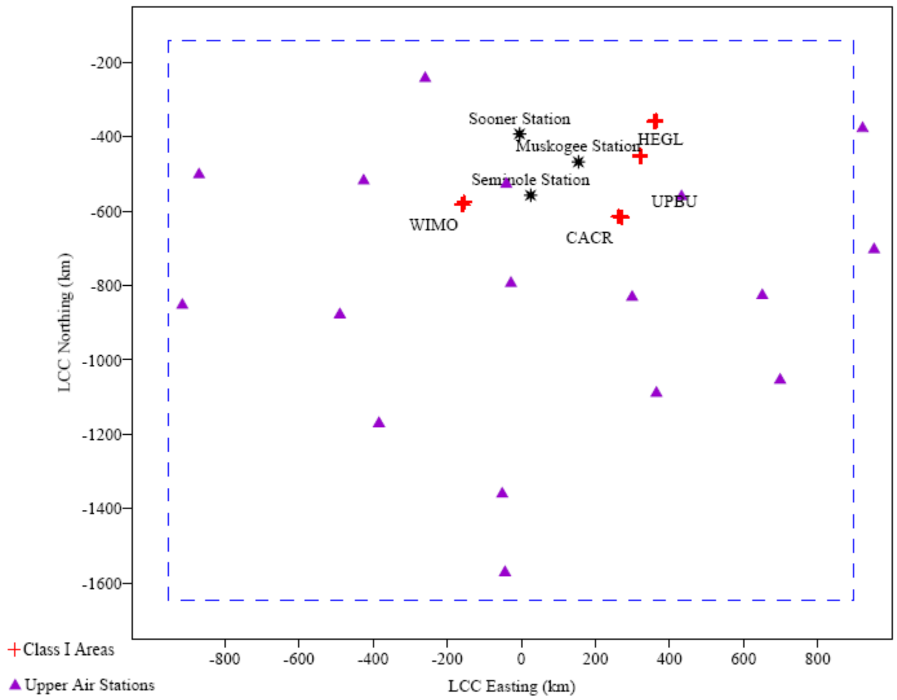

Figure 3: Plot of upper air station locations

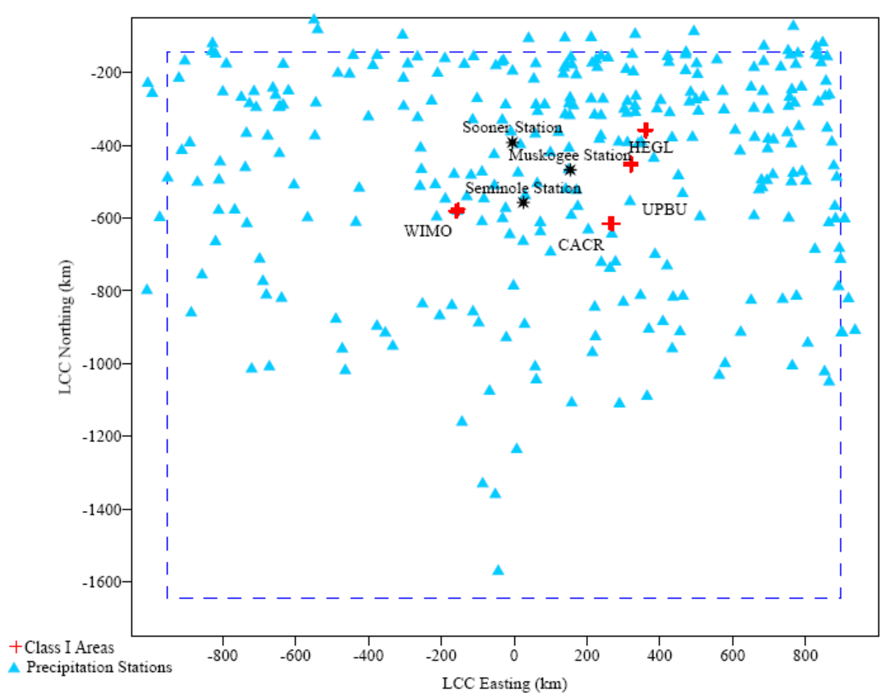

Figure 4. Plot of precipitation observation stations

CALPUFF Modeling Setup

To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia. CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. Hourly ozone data files were used in the CALPUFF simulation. As provided by the Oklahoma DEQ, hourly ozone data from the Oklahoma City, Glenpool, and Lawton monitors over the 2001-2003 time frames were used. Background concentrations for ammonia were assumed to be temporally and spatially invariant and were set to 3 ppb.

Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate LCC coordinates.

CALPUFF Inputs- Baseline and Control Options

The first step in the refined modeling analysis was to perform visibility modeling for current (baseline) operations at the facility. Emissions of NO_X and SO_2 for the baseline runs were established based on CEM data and maximum 24-hour emissions averages for years 2001 to 2003.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options.

Table 16: Source Parameters

	Baseline[1]	
Parameter	Coal-Fired Unit 4	Coal-Fired Unit 5
Heat Input (mmBtu/hr)	5,480	5,480
Stack Height (m)	106.71	106.71
Stack Diameter (m)	7.32	7.32
Stack Temperature (K)[2]	430.78	430.78
Exit Velocity (m/s)[2]	25.40	25.40
Baseline SO_2 Emissions (lb/mmBtu)	0.80	0.85
Dry FGD SO_2 Emissions (lb/mmBtu)	0.10	0.10
Wet FGD SO_2 Emissions (lb/mmBtu)	0.08	0.08
Baseline NO_X Emissions (lb/mmBtu)	0.495	0.522
LNB/OFA NO_X Emissions (lb/mmBtu)	0.15	0.15
LNB/OFA + SCR NO_X Emissions (lb/mmBtu)	0.07	0.07
ESP (Baseline) PM_{10} Emissions (lb/mmBtu)	0.0184	0.0244
FF PM_{10} Emissions (lb/mmBtu)	0.012	0.012

[1]Baseline emissions data were provided by OG&E. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum 24-hr lb/hr emission rate by the maximum heat input to the boiler.

[2]Temperature and Velocity were decreased for DFGD and WFGD evaluations. For DFGD, stack temperature was modeled at 359.11K and velocity decreased to 22.77 m/s. For WFGD, stack temperature decreased to 331.89K and velocity decreased to 21.10 m/s.

Visibility Post-Processing (CALPOST) Setup

The changes in visibility were calculated using Method 6 with the CALPOST post-processor. Method 6 requires input of monthly relative humidity factors [f(RH)] for each Class I area that is being modeled. Monthly f(RH) factors that were used for this analysis are shown in the table below.

Table 17: Relative Humidity Factors for CALPOST

Month	Wichita Mountains	Caney Creek	Upper Buffalo	Hercules Glade
January	2.7	3.4	3.3	3.2
February	2.6	3.1	3.0	2.9
March	2.4	2.9	2.7	2.7
April	2.4	3.0	2.8	2.7
May	3.0	3.6	3.4	3.3
June	2.7	3.6	3.4	3.3
July	2.3	3.4	3.4	3.3
August	2.5	3.4	3.4	3.3
September	2.9	3.6	3.6	3.4
October	2.6	3.5	3.3	3.1
November	2.7	3.4	3.2	3.1
December	2.8	3.5	3.3	3.3

EPA's default average annual aerosol concentrations for the U.S. that are included in Table 2-1 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program* were to develop natural background estimates for each Class I area.

Visibility Post-Processing Results

Table 18: CALPUFF Visibility Modeling Results for Muskogee Units 4 and 5- NO_X

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline								
Wichita Mountains	0.511	8	0.613	9	0.744	12	0.623	10
Caney Creek	0.914	37	0.939	31	1.469	33	1.107	34
Upper Buffalo	1.021	21	0.650	11	0.702	13	0.791	15
Hercules Glade	0.574	10	0.431	5	0.407	4	0.471	6
Scenario 1- Combustion Control- LNB/OFA								
Wichita Mountains	0.154	1	0.176	2	0.225	1	0.185	1
Caney Creek	0.280	1	0.283	1	0.444	4	0.336	2
Upper Buffalo	0.312	3	0.192	1	0.211	2	0.238	2
Hercules Glade	0.164	1	0.129	1	0.119	0	0.137	1

Modeling for SCR controls resulted in an approximate 50% reduction in visibility impairment from scenario one.

Table 19: CALPUFF Visibility Modeling Results for Muskogee Units 4 and 5- SO_2

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline								
Wichita Mountains	0.939	24	1.208	18	1.218	28	1.122	23
Caney Creek	1.081	34	1.287	40	1.724	50	1.364	41
Upper Buffalo	1.342	27	0.974	22	1.286	34	1.200	28
Hercules Glade	1.145	17	0.898	21	0.845	17	0.963	18
Scenario 1- Dry FGD								
Wichita Mountains	0.117	0	0.148	0	0.165	1	0.143	0
Caney Creek	0.140	0	0.171	0	0.234	2	0.182	1
Upper Buffalo	0.160	0	0.114	1	0.167	0	0.147	0
Hercules Glade	0.119	0	0.122	0	0.101	0	0.114	0

While mass emissions are decreased marginally with Wet FGD controls modeled impacts increase over modeled concentrations in scenario one for all Class I areas but the Wichita Mountains. Wet FGD reduced visibility impairment by a further 1% over Dry FGD. This generally increased degradation is a result of lower stack temperatures and velocities and higher SO_4 emission estimates.

Modeling for existing ESP controls with proposed fabric filters indicate the visibility impairment from direct PM emissions will be improved with the fabric filters but both technologies control visibility impairment well below 0.5dv at all Class I areas.

E. BART DETERMINATION

After considering: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollutant equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, the Division determined BART for the two units at the Muskogee Generating Station.

NO_X

New LNB with OFA is determined to be BART for NO_X control for Units 4 and 5 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective, with a capital cost of $14,113,700 per unit for units 4 and 5 and an average cost effectiveness of $260-$281 per ton of NO_X removed for each unit over a twenty-five year operational life.

2. Combustion control using the LNB/OFA does not require non-air quality environmental mitigation for the use of chemical reagents (i.e., ammonia or urea) and there is minimal energy impact.
3. After careful consideration of the five statutory factors, especially the costs of compliance and existing controls, NO_X control levels on 30-day rolling averages of 0.15 lb/mmBtu for Unit 4 and 5 are justified meet the presumptive limits prescribed by EPA.
4. Annual NO_X emission reductions from new LNB with OFA on Units 4 and 5 are 2,018-2,469 tons for a total annual reduction of 4,487 tons based on actual emissions from 2004-2006 and projected emissions at maximum heat input and 90% capacity.

LNB with OFA and SCR was not determined to be BART for NO_X control for Units 4and 5 based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than the cost for LNB with OFA. Additional capital costs for SCR on Units 4 and 5 are on average $193,077,000 per unit. Based on projected emissions, SCR could reduce overall NO_X emissions from Muskogee Units 4 and 5 by approximately 3,456 TPY beyond combustion controls; however, the incremental cost associated with this reduction is approximately $16,611/ton.
2. Additional non-air quality environmental mitigation is required for the use of chemical reagents.
3. Operation of LNB with OFA and SCR is parasitic and requires power from each unit.
4. The cumulative visibility improvement for SCR, as compared to LNB/OFA across Wichita Mountains and Caney Creek (based on the 98th percentile modeled results) was 0.10 and 0.18 Δdv respectively.

SO_2

Continued use of low sulfur coal is determined to be BART for SO_2 control for Units 4 and 5 based on the capital cost of add-on controls, the cost effectiveness both in $/ton and $/dv of add-on controls, and the long term viability of coal with respect to other environmental programs, and national commitments.

Installation of DFGD is not cost effective. OG&E's revised cost estimates are based on vendor quotes and go well beyond the default methodology recommended by EPA guidance. The cost estimates are credible, detailed, and specific for the Muskogee facility. The final estimate for both boilers at $634,387,200 is $223,691,200 greater than the high end costs assumed by DEQ in the Draft SIP.

These costs put the project well above costs reported for other BART determinations. The federal land managers have informally maintained a spreadsheet of BART costs and determinations for coal-fired facilities. This spreadsheet indicates that the highest reported cost for control was for the Boardman facility in Oregon at a projected cost of $247,300,000. While there is some uncertainty on whether this cost will ultimately be found to be cost effective, it is much lower than the cost of controlling a single boiler at the Muskogee facility ($317,193,600). Most assessments were based on costs of less than $150,000,000 and related cost effectiveness numbers of $3,053/ton removed for Boardman to an average of less than $2,000/ton for the other determinations tracked by the FLMs.

Table 20 provides a summary of the baseline SO_2 emission rates included in several BART evaluations.

Table 20: Comparison of Baseline SO_2 Emissions at Several BART Units

Station	Baseline SO_2 Emission Rate (lb/mmBtu)	Baseline SO_2 Emissions (TPY)
Muskogee Unit 4	0.507	9,113
Muskogee Unit 5	0.514	9,006
Sooner Unit 1	0.509	9,394
Sooner Unit 2	0.516	8,570
NPPD Gerald Gentleman Unit 1	0.749	24,254
NPPD Gerald Gentleman Unit 2	0.749	25,531
White Bluff Unit 1	0.915	31,806
White Bluff Unit 2	0.854	32,510
Boardman unit 1	0.614	14,902
Northeastern Unit 3	0.900	16,000
Northeastern Unit 4	0.900	16,000
Naughton Unit 1	1.180	8,624
Naughton Unit 2	1.180	11,187
OPPD Nebraska City Unit 1	0.815	24,191

Assuming total annual costs and projected emissions are similar and thereby setting aside the issues related to pre-2008 cost estimates and the ability to compare them to December 2009 estimates, cost effectiveness will be a function of the baseline emissions. This holds true for units firing subbituminous coals with baseline SO_2 emissions rates in the range of 0.5 lb/mmBtu to approximately 2.0 lb/mmBtu, because removal efficiencies achievable with DFGD control will vary based on inlet SO_2 loading. In general, DFGD control systems are capable of achieving higher removal efficiencies on units with higher inlet SO_2 loading. DFGD control systems will be more cost effective on units with higher baseline SO_2 emissions because the control systems will be capable of achieving higher removal efficiencies and remove more tons of SO_2 per year for similar costs. Conversely, DFGD will be less cost effective, on a $/ton basis, on units with lower SO_2 baseline emissions. On the basis of baseline emissions alone, with all other factors being equal, the cost effectiveness of the OG&E units would be about 55 to 185% higher than the other units listed, i.e., less cost effective.

The average cost effectiveness at Muskogee for DFGD is $7,378-$7,493 per ton of SO_2 removed for each unit over a twenty year operational life. The cost of this control at the Muskogee facility is well above the average cost effectiveness reported for similar BART projects, well above costs associated with BACT determinations for SO_2, and well above the cost of control originally contemplated in the Regional Haze Rule.

From the FLM BART tracking spreadsheet, the average cost effectiveness in $/dv was $5,700,000/dv. The addition of DFGD at the Muskogee Facility was anticipated to reduce impairment by 4.217 dv. Importantly, the cost effectiveness of that improvement is now calculated to be $24,330,000/dv.

A majority of the Class I areas are located in the western part of the U.S. Simply due to the number of Class I areas in the west, it is likely that a BART applicable unit located in the western U.S. will be closer to a Class I area, and that emissions from the unit will affect visibility at more Class I areas. For example, the Boardman Generating Station located in the north central region approximately 150 miles east of Portland, is located within 300 km of 14 Class I areas. By comparison the Muskogee station is located within 300 km of 4 Class I areas. Using the sum of modeled visibility improvements at all 14 Class I areas, cost effectiveness of the DFGD control system would be $3,690,510/dv or 6.5 times more cost effective than DFGD controls at the Muskogee facility. The federal land managers have indicated that costs effectiveness numbers of less than $10,000,000/dv should be considered cost effective. While this does not prohibit a determination of cost effectiveness at numbers greater than $10,000,000/dv, it does imply that numbers greater than that should receive greater consideration.

An investment of this magnitude to install DFGD on an existing coal-fired power plant effectively guarantees the continued use of coal as the primary fuel source for energy generation in this facility and arguably the state for the next 20 years and beyond. Therefore, a determination in support of DFGD ignores the Obama Administration's stated agenda to control carbon dioxide and other green house gases by restricting the alternatives left open to OG&E and hence the ratepayers of Oklahoma. Substantial uncertainty currently exists about the nature and costs of future federal carbon controls on power plants, including the level of stringency, timing, emissions allowance allocation and prices, and whether and to what degree emissions "offsets" are allowed. Further, new federal MACT mercury control requirements may be imposed on the Muskogee facility that would be more stringent than the scrubber can deliver. Fortunately, other technology options now exist that would likely achieve greater mercury reductions at lower cost than the scrubber. If EPA determines that MACT requires greater reductions than those achieved through DFGD, then ratepayers would be at risk to pay for additional required mercury control technology.

The cost for DFGD is too high, the benefit too low and these costs, if borne, further extend the life expectancy of coal as the primary fuel in the Muskogee facility for at least 20 years and beyond. BART is the continued use of low sulfur coal.

Wet FGD was not determined to be BART for SO_2 control for Units 4 and 5 based, in part, on the following conclusions:

1. The cost of compliance for installing WFGD on each unit is higher than the cost for DFGD. Based on projected emissions, WFGD could reduce overall SO_2 emissions from Muskogee Units 4 and 5 by approximately 864 TPY beyond dry scrubbers; however, the incremental cost associated with this reduction is approximately $30,381/ton.
2. SO_3 remaining in the flue gas will react with moisture in the wet FGD to generate sulfuric acid mist. Sulfuric acid is classified as a condensable particulate. Condensable particulates from the wet FGD system can be captured using additional emission controls (e.g., WESP). However, the effectiveness of a WESP system on a subbituminous fired unit has not been demonstrated and the additional cost of the WESP system significantly increases the cost of SO_2 controls.
3. Wet FGD systems must be located downstream of the unit's particulate control device;

therefore, dissolved solids from the wet FGD system will be emitted with the wet FGD plume. Wet FGD control systems also generate lower stack temperatures that can reduce plume rise and result in a visible moisture plume.

4. Wet FGD systems use more reactant (e.g., limestone) than do dry systems, therefore the limestone handling system and storage piles will generate more fugitive dust emissions.
5. Wet FGD systems require significantly more water than the dry systems and generate a wastewater stream that must be treated and discharged. We FGD wastewater treatment systems typically require calcium sulfate/sulfite desaturation, heavy metals precipitation, coagulation/precipitation, and sludge dewatering. Treated wastewater is typically discharged to surface water pursuant to an NPDES discharge permit, and solids are typically disposed of in a landfill. Dry FGD control systems are designed to evaporate water within the reaction vessel, and therefore do not generate a wastewater stream.
6. Because of a slower exit velocity, lower stack temperature and higher SO_4 emissions associated with Wet FGD, visibility impairment was found to higher under this control strategy than the Dry FGD for three of four Class I areas.

PM_{10}

The existing ESP control is determined to be BART for PM_{10} controls for Units 4 and 5 based on the determination of low sulfur coal and the high cost of fabric filters relative to the low actual emissions of PM_{10} from the facility.

Table 21: Unit-by-unit BART determinations

Control	Unit 4	Unit 5
NO_X Control	New LNB with OFA	New LNB with OFA
Emission Rate (lb/mmBtu)	0.15 lb/mmBtu (30-day rolling average)	0.15 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	822 lb/hr (30-day rolling average),	822 lb/hr (30-day rolling average),
Emission Rate TPY	3,600 TPY (12-month rolling)	3,600 TPY (12-month rolling)
SO_2 Control	Low Sulfur Coal	Low Sulfur Coal
Emission Rate (lb/mmBtu)	0.65 lb/mmBtu (30-day rolling average)	0.65 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	3,562 lb/hr (30-day rolling average)	3,562 lb/hr (30-day rolling average)
Annual Emission Rate (lb/mmBtu)	0.55 lb/mmBtu (annual average)	0.55 lb/mmBtu (annual average)
Emission Rate TPY	18,096 TPY	
PM_{10} Control	Existing ESP	Existing ESP
Emission Rate (lb/mmBtu)	0.1 lb/mmBtu	0.1 lb/mmBtu
Emission Rate lb/hr	548 lb/hr	548 lb/hr
Emission Rate TPY	2,400 TPY (12-month rolling average)	2,400 TPY (12-month rolling average)

F. CONTINGENT BART DETERMINATION

In the event that EPA disapproves the BART Determination referenced above in regard to the DEQ determination that DFGD with SDA is not cost-effective for SO_2 control, the low-sulfur coal requirement in the BART determination for SO_2 and the related ESP requirement for PM referenced above shall be replaced with a requirement that Muskogee Units 4 and 5 install DFGD with SDA for SO_2 control and fabric filters for PM control or meet the corresponding SO_2 and PM_{10} emission limits listed below by December 31, 2018 or comply with the approved alternative described in section G (Greater Reasonable Progress Alternative).

Table 22: Unit-by-unit Contingent BART determinations

Control	Unit 4	Unit 5
SO_2 Control	DFGD w/SDA	DFGD w/SDA
Emission Rate (lb/mmBtu)	0.1 lb/mmBtu (30-day rolling average)	0.1 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	548 lb/hr (30-day rolling average)	548 lb/hr (30-day rolling average)
Emission Rate TPY	2,400 TPY	2,400 TPY
PM_{10} Control	Fabric Filter	Fabric Filter
Emission Rate (lb/mmBtu)	0.015 lb/mmBtu	0.015 lb/mmBtu
Emission Rate lb/hr	82 lb/hr	82 lb/hr
Emission Rate TPY	360 TPY (12-month rolling average)	360 TPY (12-month rolling average)

The "contingent" BART as defined here and in conjunction with the greater reasonable progress alternative recognizes the long term importance of achieving reductions in SO_2 while addressing the need for operational flexibility in response to the eventualities of a federal carbon trading program and mercury MACT in the nearer term. It must be understood that DEQ has determined that DFGD is not cost effective. However, if EPA chooses to ignore that element of the BART determination, DEQ does agree that DFGD remains a technically feasible control option for SO_2 reductions.

Switching from coal to natural gas, while physically possible constitutes a significant modification to a facility process not contemplated by the regional haze rule. However, exploring some combination of both options, while allowing the uncertainty surrounding other federal environmental programs to settle, is a more equitable alternative for the ratepayers in Oklahoma than requiring an overly costly control merely to achieve limited reductions while simultaneously solidifying the use of a dirty technology from now into the foreseeable future.

G. GREATER REASONABLE PROGRESS ALTERNATIVE DETERMINATION

In lieu of installing and operating BART for SO_2 and PM control at Sooner Units 1 and 2 and Muskogee Units 4 and 5, OG&E may elect to implement a fuel switching alternative. The greater reasonable progress alternative requires OG&E to achieve a combined annual SO_2 emissions limit (identified in table 23) by installing and operating DFGD with SDA on two of the four boilers and being at or below the SO_2 emission that would result from switching the remaining two boiler to natural gas. Under this alternative OG&E shall install the controls (i.e., DFGD with SDA or achieve equivalent emissions) by December 31, 2026. By adopting these emission limits, DEQ and OG&E expect the cumulative SO_2 emissions from Sooner Units 1 and 2 and Muskogee Units 4 and 5 to be approximately 57% less than would be achieved through the installation and operation of DFGD with SDA at all four units (assuming 90% capacity).

Table 23: SO_2 Emissions with Greater Reasonable Progress

	Muskogee	Sooner
Parameter	Unit 4 and Unit 5	Unit 1 and Unit 2
BART (Low Sulfur Coal)	18,096 TPY	19,736 TPY
Contingent BART (DFGD)	4,800 TPY	4,482 TPY
GRP (DFGD/Natural Gas)	3,600 TPY	

Under no circumstance will the Greater Reasonable Progress Plan result in less visibility improvement than would be achieved either through the DEQ determined BART or the "contingent" BART. By allowing the installation of SO_2 controls to be delayed, current regulatory hurdles to long term natural gas contracts can be addressed and the best interests of the ratepayers and visitors to our Class I areas can be preserved for the long term 2064 goal of natural visibility.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)

Muskogee Generating Station is a major source under OAC 252:100-8 Permits for Part 70 Sources. Oklahoma Gas and Electric should comply with the permitting requirements of Subchapter 8 as they apply to the installation of controls determined to meet BART.

The installation of controls determined to meet BART will not change NSPS or NESHAP/MACT applicability for the gas-fired units at the Muskogee Station. The permit application should contain PM_{10} and $PM_{2.5}$ emission estimates for filterable and condensable emissions.

VI. OPERATING PERMIT

The Muskogee Generating Station is a major source under OAC 252:100-8 and has submitted an application to modify their existing Title V permit to incorporate the requirement to install controls determined to meet BART. The Permit will contain the following specific conditions:

1. The boilers in EUG 3 are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including but not limited to the following: [40 CFR §§ 51.300-309 & Part 51, Appendix Y]

   a. Affected facilities. The following sources are affected facilities and are subject to the requirements of this Specific Condition, the Protection of Visibility and Regional Haze Requirements of 40 CFR Part 51, and all applicable SIP requirements:

EU ID#	Point ID#	EU Name	Heat Capacity (MMBTUH)	Construction Date
3-B	01	Unit 4 Boiler	5,480	1972
3-B	02	Unit 5 Boiler	5,480	1972

b. Each existing affected facility shall install and operate the SIP approved BART as expeditiously as practicable but in no later than five years after approval of the SIP incorporating the BART requirements.

c. The permittee shall apply for and obtain a construction permit prior to modification of the boilers. If the modifications will result in a significant emission increase and a significant net emission increase of a regulated NSR pollutant, the applicant shall apply for a PSD construction permit.

d. The affected facilities shall be equipped with the following current combustion control technology, as determined in the submitted BART analysis, to reduce emissions of NO_X to below the emission limits below:
   i. Low-NO_X Burners,
   ii. Overfire Air.

e. The permittee shall maintain the controls (Low-NOX burners, overfire air, dry) and establish procedures to ensure the controls are properly operated and maintained.

f. Within 60 days of achieving maximum power output from each affected facility, after modification or installation of BART, not to exceed 180 days from initial start-up of the affected facility the permittee shall comply with the emission limits established in the construction permit. The emission limits established in the construction permit shall be consistent with manufacturer's data and an agreed upon safety factor. The emission limits established in the construction permit shall not exceed the following emission limits:

EU ID#	Point ID#	NO_X Emission Limit	SO_2 Emission Limit	Averaging Period
3-B	01	0.15 lb/mmBtu	0.65 lb/mmBtu	30-day rolling
3-B	02	0.15 lb/mmBtu	0.65 lb/mmBtu	30-day rolling

EU ID#	Point ID#	PM_{10}
3-B	01	0.1 lb/mmBtu
3-B	02	0.1 lb/mmBtu

EU ID#	Point ID#	SO_2 Emission Limit	SO_2 Emission Limit	Averaging Period
3-B	01	18,096 TPY	0.55 lb/mmBtu	Annual rolling
3-B	02		0.55 lb/mmBtu	Annual rolling

g. Boiler operating day shall have the same meaning as in 40 CFR Part 60, Subpart Da.

h. Within 60 days of achieving maximum power output from each boiler, after modification of the boilers, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities. [OAC 252:100-8-6(a)]

i. The permittee shall conduct SO_2, NO_X, PM_{10}, $PM_{2.5}$, CO, and VOC testing on the boilers at 60% and 100% of the maximum capacity. NOX and CO testing shall also be conducted at least one additional intermediate point in the operating range.

ii. Performance testing shall be conducted while the units are operating within 10% of the desired testing rates. A testing protocol describing how the testing will be performed shall be provided to the AQD for review and approval at least 30 days prior to the start of such testing. The permittee shall also provide notice of the actual test date to AQD.