Item 1 of Appendix 6-5

OG&E Regional Haze Agreement

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

IN THE MATTER OF: **Oklahoma Gas & Electric Company,** **Seminole Generating Station,** **Sooner Generating Station,** **Muskogee Generating Station,**	**CASE NO. 10-024**

OKLAHOMA
DEPT. OF ENVIRONMENTAL QUALITY

FEB 17 2010

FILED BY: mum
HEARING CLERK

REGIONAL HAZE AGREEMENT

The parties to this Agreement, the Oklahoma Department of Environmental Quality ("DEQ") and the Oklahoma Gas & Electric Company ("OG&E") hereby agree to the entry of this Regional Haze Agreement ("Agreement") in order to satisfy the Best Available Retrofit Technology ("BART") requirements associated with the Regional Haze Rule, 40 C.F.R. Subpart P, and 40 C.F.R. Part 51, Appendix Y (incorporated by reference at OAC 252:100-8-72).

FINDINGS OF FACT

1. OG&E is an Oklahoma corporation with its principal headquarters in Oklahoma City, Oklahoma.

2. OG&E owns and operates the following three (3) fossil-fuel fired steam electric generating plants:

> Seminole Generating Station – This station is located northeast of the City of Konawa, Seminole County, Oklahoma. The station includes three (3) nominal 567 megawatts ("MW") steam electric generating units designated as Seminole Units 1, 2, and 3. Seminole Units 1 and 2 became operational in 1968, and Unit 3 became operational in 1970. All three (3) units are Babcock & Wilcox wall-fired boilers that fire natural gas as their primary fuel. Each unit is a fossil-fuel fired

boiler with heat inputs greater than 250-mmBtu/hr. Because the units fire natural gas, there are no sulfur dioxide ("SO2") or particulate matter ("PM") emission control systems. Seminole Unit 3 was designed with flue gas recirculation ("FGR") for nitrogen oxide ("NOx") control. Each unit has the potential to emit 250 tons per year ("TPY") of NOx. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-400-TVR, which was issued on May 8, 2006.

<u>Sooner Generating Station</u> – This station is located in Red Rock, Noble County, Oklahoma. The station includes two (2) 570 MW steam electric generating units designated as Sooner Units 1 and 2. Each unit is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr. Sooner Units 1 and 2 were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Both units fire coal as their primary fuel, and both units have the potential to emit 250 TPY or more of NOx, SO2, and PM. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-274-TVR, which was issued on February 11, 2006.

<u>Muskogee Generating Station</u> – This station is located in Muskogee, Muskogee County, Oklahoma. The station includes two (2) 572 MW steam electric generating units designated as Muskogee Units 4 and 5. Each unit is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr. Both Muskogee Units 4 and 5 were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Both units fire coal as their primary fuel, and both units have the potential to emit 250 TPY or more of NOx, SO2, and PM. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2005-271-TVR, which was issued on September 8, 2009.

3. In 1977, the U.S. Congress enacted § 169 of the federal Clean Air Act, 42 U.S.C. § 7491, to protect the visibility of Class I Federal areas (areas determined to be of great scenic importance) from impairment. A particular type of visibility impairment is referred to as "Regional Haze." *See* 40 C.F.R. § 51.301 ("*Regional Haze* means visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."). The federal Clean Air Act requires the development of emission limitations for pollutants contributing to Regional Haze which emanate from a variety of sources, including fossil-fuel fired electric generating power plants having a total energy generating capacity in excess of 750

MW.

4. In 1980, the U.S. Environmental Protection Agency ("EPA") promulgated regulations addressing Regional Haze reasonably attributable to specific sources or small groups of sources. *See* 40 Fed.Reg. 80,084. The regulations required States to determine which sources impair visibility and require the installation of BART on certain of those sources.

5. In 1999, EPA amended 40 C.F.R. Part 51, Subpart P, to further define the facilities subject to the Regional Haze requirements. The regulations require States to develop and implement long-term strategies for reducing air pollutants that cause or contribute to visibility impairment in Class I Federal areas.

6. On July 6, 2005, the EPA published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule"). *See* 70 Fed.Reg. 39104. The federal Clean Air Act, 42 U.S.C. §§ 7401 *et seq.*, and the Regional Haze Rule, 40 C.F.R. §§ 51.300 – 51.309, require certain States, including Oklahoma, to make reasonable progress toward the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas." 42 U.S.C. §§ 7491(a)(1), (b)(2) and 40 C.F.R. § 51.300. Moreover, the Regional Haze Rule requires the State of Oklahoma to develop programs to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State." 40 C.F.R. § 51.308(d); *see also* 40 C.F.R. § 51.300(b).

7. In order to meet the requirements of the Regional Haze Rule, States must submit State Implementation Plans ("SIP") implementing the requirements of the Regional Haze Rule to EPA for approval. *See id.* The States were required to submit their SIPs prior to December 17,

2007. *See* 40 C.F.R. § 51.308(b). Each Regional Haze SIP must contain "emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area . . . ." *See* 40 C.F.R. § 51.308(e).

8. 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). *See* OAC 252:100-8-71, 40 C.F.R. Part 51, Appendix Y(I)(C)(1), *and* 42 U.S.C. § 7491(b)(2)(A).

9. "Air pollutants emitted by sources in Oklahoma which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I federal area are NOx, SO2, PM-10, and PM-2.5." OAC 252:100-8-73(b).

10. As stated in Paragraph 2 above, Seminole Units 1, 2 and 3, Sooner Units 1 and 2, and Muskogee Units 4 and 5, are all: fossil-fuel fired boilers with heat inputs greater than 250 mmBtu/hr; units that were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962; and, based on a review of existing emissions data, units that have the potential to emit more than 250 tons per year of a visibility impairing pollutant. Consequently, all seven (7) units meet the definition of a BART-eligible source.

11. 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. *See* OAC 252:100-8-73(a), 42 U.S.C. § 7491(b)(2)(a), *and* 40 C.F.R. § 51.308(e).

EPA 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. *See* 40 C.F.R. Part 51, Appendix Y(III)(A)(1); *see also* 70 Fed.Reg. 39,120; *and* OAC 252:100-8-73(a). Visibility impact modeling indicates that the maximum predicted visibility impacts from all seven (7) of the OG&E units listed in Paragraph 2 above exceed the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. *See* State of Oklahoma Regional Haze SIP, p. 72, table VI-4. Therefore, all seven (7) units are subject to the BART determination requirements.

12. Since the Seminole Generating Station, the Sooner Generating Station, and the Muskogee Generating Station each have a total generating capacity in excess of 750 MW, the Appendix Y guidelines were used to prepare BART determinations for each station. Based on an evaluation of potentially feasible retrofit control technologies, including an assessment of the costs and visibility improvements associated therewith, the following control technologies and emission limits as described in the BART Determinations for each of the three (3) stations (attached as Exhibits A, B, and C; collectively "BART Determinations") have been determined to be BART and shall be implemented within 5 years of EPA's approval of Oklahoma's Regional Haze SIP:

<u>Seminole Generating Station</u> -

Control	Unit 1	Unit 2	Unit 3
NO_X Control	Combustion controls including: Low-NO_X Burners, Overfire Air, and Flue Gas Recirculation	Combustion controls including: Low-NO_X Burners, Overfire Air, and Flue Gas Recirculation	Combustion controls including: Low-NO_X Burners, Overfire Air, and Flue Gas Recirculation
NOx Emission Rate (lb/mmBtu)	0.203 lb/mmBtu (30-day average)	0.212 lb/mmBtu (30-day average)	0.164 lb/mmBtu (30-day average)

__Sooner Generating Station__ -

Control	Unit 1	Unit 2
NO_X Control	***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	767 lb/hr (30-day rolling average)	767 lb/hr (30-day rolling average)
Emission Rate TPY	3,361 TPY (12-month rolling)	3,361 TPY (12-month rolling)
SO2 Control	***Low Sulfur Coal***	***Low Sulfur Coal***
Hourly Emission Rate (lb/mmBtu)	0.65 lb/mmBtu (30-day rolling average)	0.65 lb/mmBtu (30-day rolling average)
Emission Rate (lb/hr)	3,325 lb/hr (30-day rolling average)	3,325 lb/hr (30-day rolling average)
Annual Emission Rate (lb/mmBtu)	0.55 lb/mmBtu (12-month rolling average)	0.55 lb/mmBtu (12-month rolling average)
Combined Annual Emission Rate (TPY)	19,736 TPY	
PM_{10} Control	***Existing Electrostatic Precipitator***	***Existing Electrostatic Precipitator***
Emission Rate (lb/mmBtu)	0.10 lb/mmBtu (3-hour rolling average)	0.10 lb/mmBtu (3-hour rolling average)
Emission Rate lb/hr	512 lb/hr (3-hour rolling average)	512 lb/hr (3-hour rolling average)
Emission Rate TPY	2,241 TPY (12-month rolling average)	2,241 TPY (12-month rolling average)

__Muskogee Generating Station Units 4 and 5__ -

Control	Unit 4	Unit 5
NO_X Control	**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)
SO2 Control	***Low Sulfur Coal***	***Low Sulfur Coal***
Hourly 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 (12-month rolling average)	0.55 lbmmBtu (12-month rolling average)
Combined Annual Emission Rate (TPY)	18,096 TPY	
PM_{10} Control	***Electrostatic Precipitator***	***Electrostatic Precipitator***
Emission Rate (lb/mmBtu)	0.10 lb/mmBtu (3-hour rolling average)	0.10 lb/mmBtu (3-hour rolling average)
Emission Rate lb/hr	548 lb/hr (3-hour rolling average)	548 lb/hr (3-hour rolling average)
Emission Rate TPY	2,400 TPY (12-month rolling average)	2,400 TPY (12-month rolling average)

13. In the event that: (i) EPA disapproves the DEQ determination described in the BART Determinations that Dry-Flue Gas Desulfurization with Spray Dryer Absorber ("Dry FGD with SDA") is not cost-effective for SO2 control and (ii) all administrative and judicial appeals of EPA's disapproval have been exhausted, then the low-sulfur coal requirement in Paragraph 12 and the BART Determinations for SO2 (and the related electrostatic precipitator requirement for PM) shall be replaced with a requirement that Sooner Units 1 and 2 and Muskogee Units 4 and 5 shall, at the election of the owner and operator of the Unit, either: (i) install Dry FGD with SDA (and install fabric filters for PM control) or meet the corresponding SO2 and PM emission limits listed below (and further described in the Section on Contingent BART Determinations, *see* § IV(F) of Exhibits B and C, collectively "Contingent BART Determinations") by January 1, 2018; or (ii) comply with the approved alternative described in Paragraph 14 prior to December 31, 2026:

<u>Sooner Generating Station</u> -

Control	Unit 1	Unit 2
SO2 Control	***Dry FGD with SDA***	***Dry FGD with 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	512 lb/hr (30-day rolling average)	512 lb/hr (30-day rolling average)
Emission Rate TPY	2,241 TPY (12-month rolling average)	2,241 TPY (12-month rolling average)

PM10 Control	Fabric Filter	Fabric Filter
Emission Rate (lb/mmBtu)	0.015 lb/mmBtu (3-hour rolling average)	0.015 lb/mmBtu (30-hour rolling average)
Emission Rate lb/hr	77 lb/hr (30-hour rolling average)	77 lb/hr (30-hour rolling average)
Emission Rate TPY	336 TPY (12-month rolling average)	336 TPY (12-month rolling average)

<u>Muskogee Generating Station Units 4 and 5</u> -

Control	Unit 4	Unit 5
SO2 Control	**Dry FGD with SDA**	**Dry FGD with 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 (12-month rolling average)	2,400 TPY (12-month rolling average)
PM10 Control	**Fabric Filter**	**Fabric Filter**
Emission Rate (lb/mmBtu)	0.015 lb/mmBtu (3-hour rolling average)	0.015 lb/mmBtu (30-hour rolling average)
Emission Rate lb/hr	82 lb/hr (30-hour rolling average)	82 lb/hr (30-hour rolling average)
Emission Rate TPY	360 TPY (12-month rolling average)	360 TPY (12-month rolling average)

14. In lieu of installing and operating BART for SO2 and PM control at the four (4) coal fired units (i.e., Sooner Units 1 and 2 and Muskogee Units 4 and 5), OG&E may elect to implement the fuel switching alternative approved pursuant to 40 C.F.R. § 51.308(e)(2) and as part of the long-term strategy in fulfillment of 40 C.F.R. § 51.308(d)(3). *See* Sections on Greater Reasonable Progress Alternative Determination, § IV(G) of Exhibits B and C (collectively "Alternative Determination"). As detailed in the Alternative Determination, implementation of this alternative requires OG&E to achieve by December 31, 2026 a combined annual SO2 emission limit that is equivalent to: (i) the SO2 emission limits provided in Paragraph 13 for installing and operating Dry FGD with SDA on two of these coal fired units; and (ii) being at or below the SO2 emissions that

would result from switching the other two of the coal fired units to natural gas. By adopting the emission limits described in the previous sentence, DEQ and OG&E expect the cumulative SO2 emissions from Sooner Units 1 and 2 and Muskogee Units 4 and 5 to be approximately fifty-seven percent (57%) less than would be achieved through the installation and operation of Dry FGD with SDA at all four (4) units. *See* Alternative Determination. If OG&E has elected to comply with the emission limits provided in this Paragraph 14 and if, prior to January 1, 2022, any of these units is required by any environmental law other than the Regional Haze Rule to install flue gas desulfurization equipment or achieve an SO2 emissions rate lower than 0.10 lb/mmBtu, and if OG&E proceeds to take all necessary steps to comply with such legal requirement, the enforceable emission limits adopted pursuant to this Paragraph 14 in the operating permits for the affected coal units shall be adjusted, with the reasonable consent of DEQ and OG&E, as appropriate to reflect the installation of that equipment or the emission rates specified under such legal requirement.

15. OG&E and DEQ agree that it is beneficial to resolve this matter promptly and by agreement.

16. OG&E and DEQ waive the filing of a petition or other pleading, and OG&E waives the right to a hearing.

CONCLUSIONS OF LAW

17. DEQ has regulatory jurisdiction and authority in this matter, and OG&E is subject to the jurisdiction and authority of DEQ under Oklahoma law, 27A Okla. Stat. ("O.S.") §§ 2-5-101 to -118, and the rules promulgated thereunder at Oklahoma Administrative Code ("OAC"), Title 252, Chapter 100, Air Pollution Control. This Order is executed under the authority of, and in conformity with, 27A O.S. § 2-5-110(G).

18. OG&E and DEQ are authorized by 75 O.S. § 309(E) and 27A O.S. § 2-3-506(B) to resolve this matter by agreement.

19. "Air pollutants emitted by sources in Oklahoma which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I federal area are NOx, SO2, PM-10, and PM-2.5." OAC 252:100-8-73(b).

20. DEQ administrative rules provide that BART applicability "shall be determined using the criteria in Section III of Appendix of 40 CFR 51 in effect on July 6, 2005." OAC 252:100-8-73(a); *see also* OAC 252:100-8-72 ("Appendix Y, Guidelines for BART Determinations Under the Regional Haze Rule, of 40 CFR 51 is hereby incorporated by reference as it exists July 6, 2005."). Similarly, the corresponding Federal regulations provide, "[t]he determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts [MW] must be made pursuant to the guidelines in appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule)." *See* 40 C.F.R. § 51.308(e)(1)(ii)(B); see *also* 42 U.S.C. § 7491(b)(2)(B). As described in Paragraph 2 of the Statement of Facts, each of the Seminole Generating Station, Sooner Generating Station, and Muskogee Generating Station, has a total generating capacity greater than 750 MW and, therefore, the BART determinations for each of these stations must be made pursuant to the "Guidelines for BART Determinations Under the Regional Haze Rule." Nothing in this Agreement shall be construed as applying emission limits to any units that are not subject to BART under the Regional Haze Rule, including Muskogee Unit 6

21. State and Federal rules define BART-eligible sources to 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). *See* OAC 252:100-8-71, 40 C.F.R. Part 51, Appendix Y(I)(C)(1), *and* 42 U.S.C. § 7491(b)(2)(A). As stated in Paragraphs 2 and 10 of the Statement of Facts, Seminole Units 1, 2, and 3, Sooner Units 1 and 2, and Muskogee Units 4 and 5 meet all three (3) criteria listed above and, therefore, meet the definition of a BART eligible source.

22. OAC 252:100-8-73(a) provides in part:

> Each BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area is subject to BART. This shall be determined using the criteria in Section III of Appendix Y of 40 CFR 51 in effect on July 6, 2005. Thresholds for visibility impairment are set forth in OAC 252:100-8-73(a)(1) and (2).
>
> (1) A source that is responsible for an impact of 1.0 deciview or more is considered to cause visibility impairment.
>
> (2) A source that causes an impact greater than 0.5 deciviews contributes to visibility impairment.

As stated in Paragraph 11 of the Statement of Facts, Seminole Units 1, 2, and 3, Sooner Units 1 and 2, and Muskogee Units 4 and 5, each contribute greater than 0.5 deciviews to visibility impairment at the Wichita Mountains Class I Area and, therefore, are considered subject to BART.

23. OAC 252:100-8-75(e) provides that "[t]he owner or operator of each BART-eligible source subject to BART shall install and operate BART no later than five years after EPA approves the Oklahoma Regional Haze SIP." Similarly, the Federal rule states that each Regional Haze SIP must contain "[a] requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years

after approval of the implementation plan revision." 40 C.F.R. § 51.308(e)(1)(iv).

24. In lieu of installing and operating BART, the Federal rules provide that States may allow BART subject sources to implement an alternative demonstrated to "achieve greater reasonable progress toward natural visibility conditions." *See* 40 C.F.R. § 51.308(e). Any approved Greater Reasonable Progress Alternative shall comply with the requirements of 40 C.F.R. § 51.308(e)(2).

25. In addition to the BART requirements, the Federal rules give States authority to adopt "emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals" as part of the long-term strategy that addresses regional haze visibility impairment. *See* 40 C.F.R. § 51.308(d)(3).

AGREEMENT

26. Based on the above paragraphs, OG&E and the DEQ agree, and it is ordered by the Executive Director as follows:

A. OG&E, at its election, shall either: (i) install and operate BART and achieve the related emission limits at the Sooner Generating Station, the Seminole Generating Station, and the Muskogee Generating Station as set forth in Paragraph 12 and the corresponding BART Determinations, within 5 years of EPA's approval of Oklahoma's Regional Haze SIP; or (ii) implement the approved Greater Reasonable Progress Alternative (i.e., natural gas fuel switching alternative) described in Paragraph 14 and the Alternative Determinations by December 31, 2026.

B. In the event that EPA disapproves the DEQ determination that Dry FGD with SDA is not cost-effective for SO2 control at Sooner Units 1 and 2 and Muskogee Units 4 and 5 and such disapproval is upheld after all judicial and/or administrative appeals have been exhausted, the SO2 related portions of the BART Determinations and the related SO2 and PM10 emission limits set forth in Paragraph 12 shall not have any further force or effect, and OG&E, at its election, shall either: (i) achieve the SO2 and PM10 emission limits at the Sooner Units 1 and 2 and the Muskogee Units 4 and 5 on or before January 1, 2018 as set forth in Paragraph 13 and the corresponding Contingent BART Determinations; or (ii) implement the approved Greater Reasonable Progress Alternative (i.e., natural gas fuel switching alternative) on or before December 31, 2026 as set forth in Paragraph 14 and the Alternative

Determinations.

27. Any control equipment required to be installed as BART shall be properly operated and maintained. *See* 40 C.F.R. § 51.308(e)(v).

28. Nothing in this Agreement shall constitute or be construed as a release for any claim or cause of action related to any NSR or New Source Performance Standard ("NSPS") liability under the Clean Air Act or the rules promulgated thereunder.

29. The emission limits required by this Agreement shall be incorporated into any otherwise required construction or operating permit issued to OG&E for the affected units.

30. This Agreement shall be incorporated into the Regional Haze State Implementation Plan submitted to EPA for approval by the State of Oklahoma.

GENERAL PROVISIONS

31. OG&E agrees to perform the requirements of this Agreement within the time frames specified unless performance is prevented or delayed by events which are a "force majeure." For purposes of this Agreement, a force majeure event is defined as any event arising from causes beyond the reasonable control of OG&E or OG&E's contractors, subcontractors or laboratories which delays or prevents the performance of any obligation under this Agreement. Examples are vandalism; fire; flood; labor disputes or strikes; weather conditions which prevent or seriously impair construction activities; civil disorder or unrest; and "acts of God." Force majeure events do *not* include increased costs of performance of the tasks agreed to in this Agreement, or changed economic circumstances. OG&E must notify DEQ in writing within thirty (30) days after OG&E knows or should have known of a force majeure event that is expected to cause a delay in achieving compliance with any requirement of this Agreement. Failure to submit notification within thirty (30) days waives the right to claim force majeure.

32. No informal advice, guidance, suggestions or comments by employees of DEQ regarding reports, plans, specifications, schedules, and other writings affect OG&E's obligation to obtain written approval by DEQ, when required by this Agreement.

33. Unless otherwise specified, any report, notice or other communication required under this Agreement must be in writing and must be sent to:

For the Department of Environmental Quality:

Eddie Terrill, Director
Air Quality Division
P.O. Box 1677
Oklahoma City, OK 73101-1677

With copies to:

Robert D. Singletary
Environmental Attorney Supervisor
Oklahoma Department of Environmental Quality
Office of General Counsel
P.O. Box 1677
Oklahoma City, OK 73101-1677

Lee Warden, Environmental Engineering Manager
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

For OG&E:

Ford Benham
Supervisor, Air Quality
Oklahoma Gas & Electric Company
321 N. Harvey
Oklahoma City, OK 73102

With copies to:

Kimber Shoop
Senior Attorney
Oklahoma Gas & Electric Company
321 N. Harvey
Oklahoma City, OK 73102

34. This Agreement is enforceable as a final order of the Executive Director of DEQ. DEQ retains jurisdiction of this matter for the purposes of interpreting, implementing and enforcing the terms and conditions of this Agreement and for the purpose of resolving disputes.

35. Nothing in this Agreement limits DEQ's right to take enforcement action for violations discovered or occurring after the effective date of this Agreement.

36. Nothing in this Agreement excuses OG&E from its obligation to comply with all applicable federal, state and local statutes, rules and ordinances. OG&E and DEQ agree that the provisions of this Agreement are considered severable, and if a court of competent jurisdiction finds any provisions to be unenforceable because they are inconsistent with state or federal law, the remaining provisions will remain in full effect.

37. To ensure continuous and uninterrupted responsibility for the activities required by this Agreement, OG&E agrees to provide a copy of the Agreement to any purchaser of an affected unit prior to sale. OG&E agrees to notify any such purchaser that the obligations under this Agreement are binding on the purchaser and shall notify DEQ of the sale within ten (10) days thereof and provide DEQ with the name of the purchaser..

38. The provisions of this Agreement apply to and bind OG&E and DEQ and their officers, directors, employees, agents, successors and assigns. No change in the ownership or corporate status of OG&E will affect OG&E's responsibilities under this Agreement.

39. This Agreement is for the purpose of settlement. Neither the fact that OG&E and

DEQ have agreed to this Agreement, nor the Findings of Fact and Conclusions of Law in it, shall be used for any purpose in any proceeding except the enforcement by OG&E and DEQ of this Agreement and, if applicable, a future determination by DEQ of eligibility for licensing or permitting. As to others who are not parties to this Agreement, nothing contained in this Agreement is an admission by OG&E of the Findings of Fact or Conclusions of Law, and this Agreement is not an admission by OG&E of liability for conditions at or near the facility and is not a waiver of any right, cause of action or defense OG&E otherwise has.

40. OG&E and DEQ agree that the venue of any action in district court for the purposes of interpreting, implementing and enforcing this Agreement will be Oklahoma County, Oklahoma.

41. The requirements of this Agreement will be considered satisfied and this Agreement terminated when OG&E receives written notice from DEQ that OG&E has demonstrated that all the terms of the Agreement have been completed to the satisfaction of DEQ, and that any assessed penalty has been paid.

42. OG&E and DEQ may amend this Agreement by mutual consent. Such amendments must be in writing and the effective date of the amendments will be the date on which they are filed by DEQ.

43. The individuals signing this Agreement certify that they are authorized to sign it and to legally bind the parties they represent.

44. This Agreement becomes effective on the date of the later of the two signatures below.

Date: 1-18-10

FOR THE OKLAHOMA GAS & ELECTRIC COMPANY:

PETER B. DELANEY
CHIEF EXECUTIVE OFFICER

Date: 2-17-10

FOR THE OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY:

STEVEN A. THOMPSON
EXECUTIVE DIRECTOR

Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis September 28, 2009

COMPANY:	**Oklahoma Gas and Electric**
FACILITY:	**Seminole Generating Station**
FACILITY LOCATION:	**Konawa, Seminole County, Oklahoma**
TYPE OF OPERATION:	**(3) 567 MW Steam Electric Generating Units**
REVIEWER:	**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).

Seminole Units 1, 2 and 3 are fossil-fuel fired boilers with heat inputs greater than 250-mmBtu/hr. All three 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, all three units have the potential to emit more than 250 tons per year of NO_X, a visibility impairing pollutant. Therefore, Seminole Units 1, 2 and 3 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 Seminole Units 1, 2 and 3 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, Seminole Units 1, 2 and 3 were determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Seminole Units 1, 2 and 3 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, baseline 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 maximum hourly mass emission rates for each boiler by the boiler's full load heat input.

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

Parameter	Seminole Unit 1		Seminole Unit 2		Seminole Unit 3	
Plant Configuration	Natural Gas-Fired Boiler		Natural Gas-Fired Boiler		Natural Gas-Fired Boiler	
Firing Configuration	Wall-fired		Wall-fired		Wall-fired	
Gross Output (nominal)	567 MW		567 MW		567 MW	
Maximum Input to Boiler	5,480 mmBtu/hr		5,480 mmBtu/hr		5,496 mmBtu/hr	
Primary Fuel	Natural gas		Natural gas		Natural gas	
Existing NO_X Controls	None		None		Flue gas recirculation	
Existing PM_{10} Controls	NA		NA		NA	
Existing SO_2 Controls	NA		NA		NA	
Baseline Emissions Pollutant	**Baseline Actual Emissions**		**Baseline Actual Emissions**		**Baseline Actual Emissions**	
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	**1,859**	**0.339**	**1,940**	**0.354**	**1,204**	**0.219**

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.

Because the units fire natural gas, emissions of sulfur dioxide (SO_2) and particulate matter (PM) are minimal. There are no SO_2 or PM post-combustion control technologies with a practical application to natural gas-fired boilers. BART is good combustion practices. A full BART analysis was conducted for NO_X.

Table 2: Proposed BART **Controls and Limits**

Unit	NO_X BART Emission Limit	BART Technology
Seminole Unit 1	0.203 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA and FGR
Seminole Unit 2	0.212 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA and FGR
Seminole Unit 3	0.164 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA and FGR

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 Seminole Units 1, 2 and 3 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 Process
Wet NO_X Scrubbing

In support of the Regional Haze Rule, EPA also prepared a cost-effectiveness analysis for retrofit control technologies on oil- and gas-fired units. EPA's analysis concluded that, although a number of oil- and gas-fired units could make significant cost-effective reductions in NO_X emissions using currently available combustion control technologies, for a number of units the use of combustion controls did not appear to be cost effective. As a result, EPA determined that it would be inappropriate to establish a general presumption regarding likely BART limits for oil- and natural gas fired units.

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 natural gas-fired boilers. Boilers of the size and age of the Seminole Units would be expected to achieve an average emission reduction in the range of 25% to 40% from baseline depending on the baseline emission rate and boiler operating conditions. Seminole units 1, 2, and 3 do not operate as base load units. The units have historically operated as "peaking units" responding to increased demand for electricity. While technically feasible, LNB/OFA may not be as effective under all boiler operating conditions, especially during load changes and at low and high operating loads. Based on information available from burner control vendors and engineering judgment, it is expected that LNB/OFA on the wall-fired boilers can be designed to achieve an average efficiency of 25% from baseline emissions under all normal operating conditions.

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. Seminole Unit 3 is currently designed with FGR control.

FGR may be applied in one of two techniques. Both designs are technically feasible retrofit options for gas-boilers. Either system would be expected to achieve an additional 15% reduction above LNB/OFA or approximately 40% overall reduction from baseline.

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 Seminole 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 Seminole 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. This design would tend to result in relatively high levels of ammonia slip. Further, because the Seminole boilers are typically used as peaking units, boiler load is continually changing. Boiler load changes affect flue gas flow rates and temperatures, which would make it particularly difficult to inject the needed quantity of reactant.

Installation of SNCR on large boilers, such as those at Seminole, has not been demonstrated in practice. Assuming that SNCR could be installed on the Seminole 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 Seminole 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 gas-fired boilers. Based on emissions data available from the EPA Electronic Reporting website, large gas-fired boilers (with heat inputs above approximately 1,000 mmBtu/hr) have achieved actual long-term average NO_X emission rates in the range of approximately 0.02 to 0.05 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 gas-fired units, and taking into consideration long-term operation of an SCR control system (including catalyst plugging and deactivation) and the fact that the Seminole boilers typically operate as peaking units, it is anticipated that SCR could achieve a controlled NO_X emission rate of 0.04 lb/mmBtu (30-day rolling average) on Seminole Units 1, 2 and 3.

Innovative NOX 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.

As discussed in 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 Seminole Units 1, 2 and 3. However, there is no technical basis to conclude that the ROFA design would provide additional NO_X 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 Seminole 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.9 The New & Emerging Environmental Technologies (NEET) Database identifies the development status of the Pahlman Process as full-scale development and testing. 10 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 Seminole Units 1, 2 and 3. 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 Seminole 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 Seminole Boilers

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Seminole Station

	Seminole Unit 1	Seminole Unit 2	Seminole Unit 3
Control Technology	Approximate NO_X Emission Rate (lb/mmBtu)	Approximate NO_X Emission Rate (lb/mmBtu)	Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.04	0.04	0.04
LNB/OFA + FGR	0.203	0.212	0.164
LNB/OFA	0.254	0.266	NA
Baseline	0.339	0.354	0.219

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

OG&E evaluated the economic, environmental, and energy impacts associated with the three 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 Seminole Units 1, 2 and 3 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. OG&E provided a summary of historical capacity factors which typically ranged between approximately 25% to 30%. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 50%.

Table 5: Economic Cost Per Boiler

Cost	Unit	Option 1: LNB/OFA	Option 2: LNB/OFA w/FGR	Option 3: LNB/OFA +SCR
Control Equipment Capital Cost ($)	Unit 1	$9,432,200	$16,977,200	$104,230,200
	Unit 2	$9,432,200	$16,977,200	$104,230,200
	Unit 3	$9,468,600	$9,468,600	$104,834,200
Capital Recover Factor ($/Yr)	Unit 1	$809,300	$1,456,700	$8,943,000
	Unit 2	$809,300	$1,456,700	$8,943,000
	Unit 3	$812,400	$812,400	$8,994,800
Annual O&M Costs ($/Yr)	Unit 1	$588,600	$1,190,900	$8,152,800
	Unit 2	$588,600	$1,190,900	$8,175,600
	Unit 3	$590,800	$590,800	$8,023,800
Annual Cost of Control ($)	Unit 1	$1,397,900	$2,647,600	$17,095,800
	Unit 2	$1,397,900	$2,647,600	$17,118,600
	Unit 3	$1,403,200	$1,403,200	$17,018,600

Table 6: Environmental Costs per Boiler

		Baseline	Option 1: LNB/OFA	Option 2: LNB/OFA w/FGR	Option 3: LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu)	Unit 1	0.339	0.254	0.203	0.04
	Unit 2	0.354	0.266	0.212	0.04
	Unit 3	0.219	0.164	0.164	0.04
Annual NO_X Emission (TPY)[1]	Unit 1	4,068	3,048	2,436	480
	Unit 2	4,248	3,192	2,544	480
	Unit 3	2,636	1,974	1,974	481
Annual NO_X Reduction (TPY)	Unit 1	–	1020	1632	3588
	Unit 2		1056	1704	3768
	Unit 3		662	662	2155
Annual Cost of Control[2]	Unit 1		$1,397,900	$2,647,600	$17,095,800
	Unit 2		$1,397,900	$2,647,600	$17,118,600
	Unit 3		$1,403,200	$1,403,200	$17,018,600
Cost per Ton of Reduction	Unit 1		$1,370	$1,622	$4,765
	Unit 2		$1,324	$1,554	$4,543
	Unit 3		$2,120	$2,120	$7,897
Incremental Cost per ton of Reduction[3]	Unit 1	N/A	--	$2,042	$7,387
	Unit 2			$1,929	$7,011
	Unit 3			--	$10,459

[1] Emissions for the BART analysis are based on maximum heat inputs of 5,480 mmBtu/hr (Units 1 & 2) and 5,496 mmBtu/hr (Unit 3). Annual emissions were calculated assuming 4,380 hours/year per boiler (50% capacity factor).
[2] Total annual cost for all three units are not additive because Unit 3 is currently equipped with FGR control and Unit 3 has a slightly higher heat input.
[3] Incremental cost effectiveness of the FGR system is compared to costs/emissions associated with LNB/OFA controls. Similarly, incremental cost effectiveness of the SCR system is compared to costs/emissions associated with LNB/OFA+FGR controls.

B. 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 Seminole 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 Seminole 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 Seminole Generating Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Seminole 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.

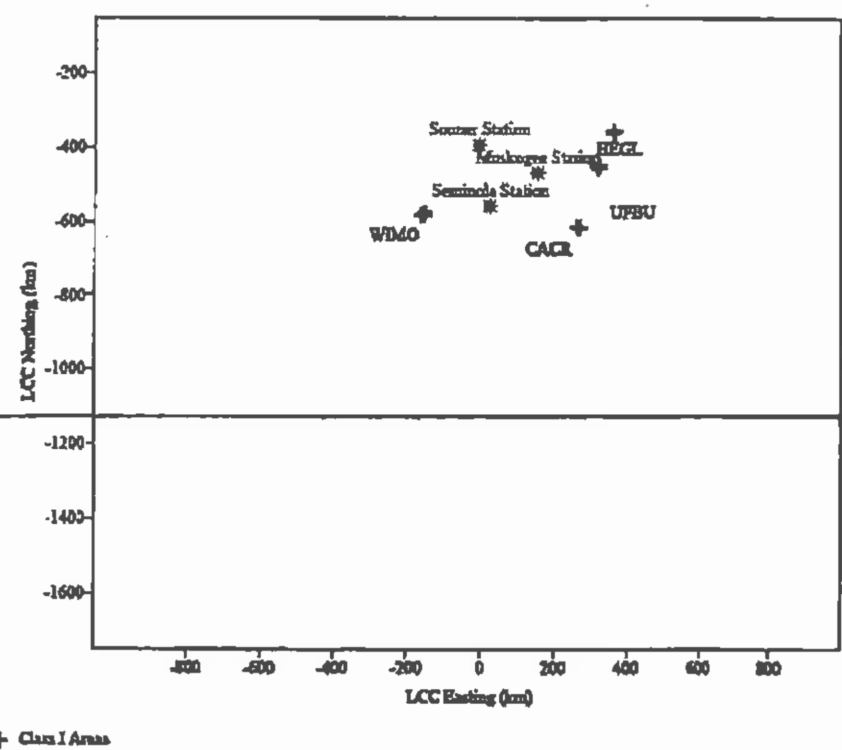

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING:

Because of the results of the applicants screening modeling for the Seminole 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 Seminole 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 7: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.51	030709

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 8: 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, 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.

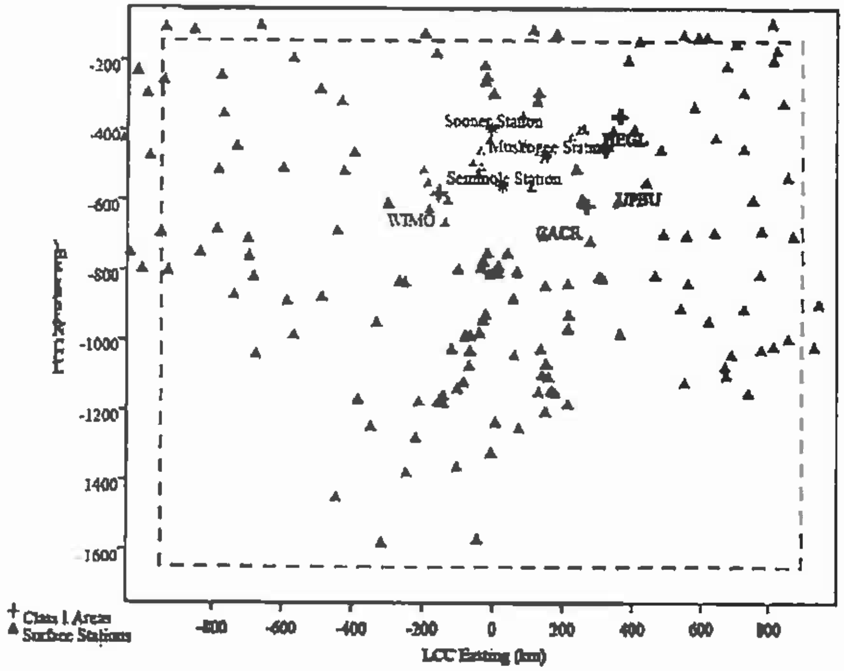

Figure 2: Plot of surface station locations

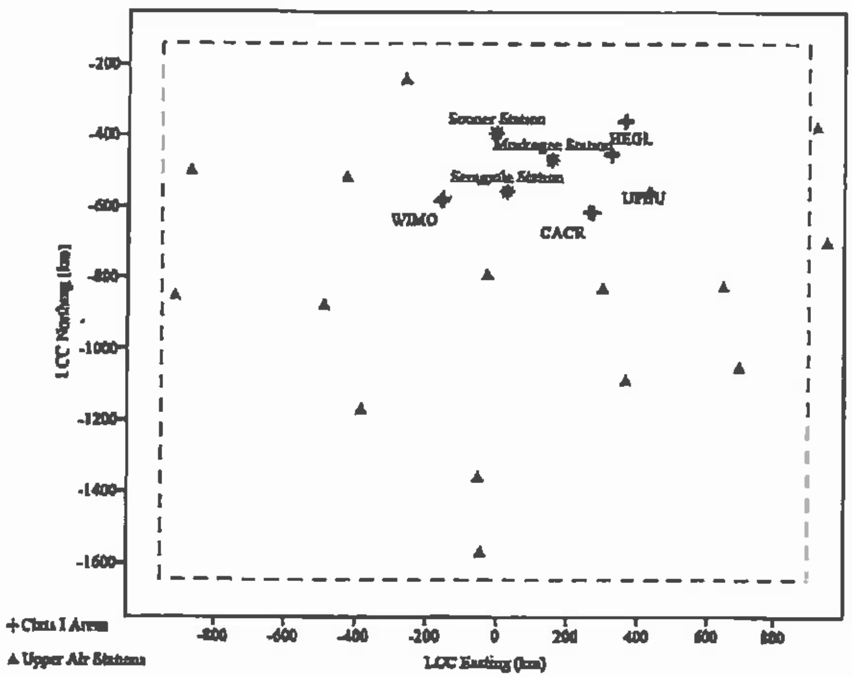

Figure 3: Plot of upper air station locations

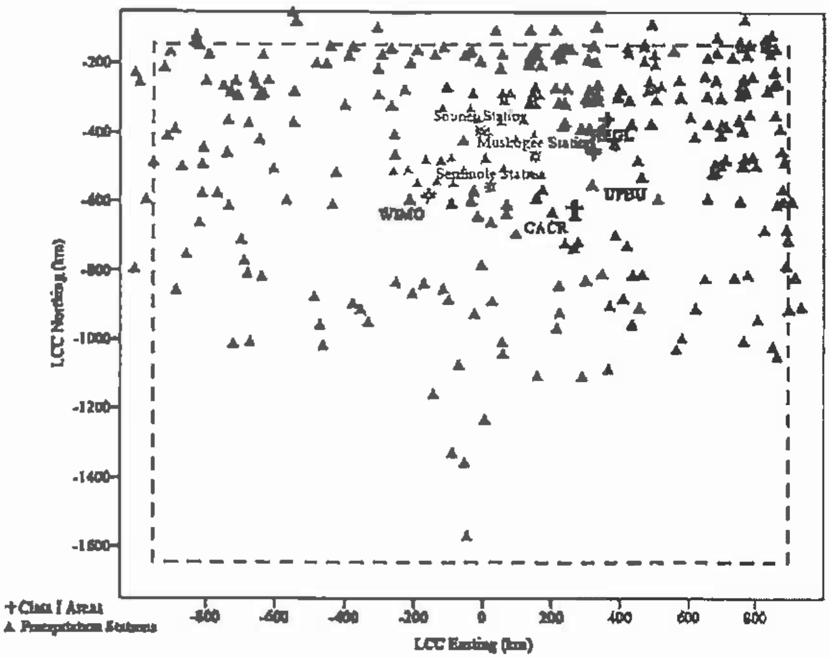

Figure 4. Plot of precipitation observation stations

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 1 area discrete receptors were taken from the National Park Service (NPS) Class 1 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 for the baseline runs were established based on CEM data and maximum 24-hour emissions averages for years 2001 to 2003. All particulate emissions (PM) were based on emission rates of 0.00186 lb/mmBtu (filterable) and were treated as PM_{10} (coarse PM) and 0.00559 lb/mmBtu (condensable) and were treated as $PM_{2.5}$ (fine PM) within CALPUFF and CALPOST. Direct emissions of sulfate were based on the values calculated for the Toxic Release Inventory (TRI) for the years modeled.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options. No attempt was made by the applicant to estimate the increase in sulfate emissions that would result from operations of SCR, and as a result the visibility improvement for those scenarios may be overestimated by some undetermined amount.

Table 9: Baseline Source Parameters

Parameter	Baseline Natural Gas-Fired Unit 1	Baseline Natural Gas-Fired Unit 2	Baseline Natural Gas-Fired Unit 3 (FGR)
Heat Input (mmBtu/hr)	5,480	5,480	5,496
Base Elevation (m)	290	290	290
Stack Height (m)	54.27	54.27	106.71
Stack Diameter (m)	4.57	4.57	5.49
Stack Temperature (K)	392.44	392.44	411.89
Exit Velocity (m/s)	42.32	42.32	30.95
SO2 Emissions (lb/mmBtu)	0.00055	0.00042	0.00060
SO2 Emissions (TPY)	13.20	10.08	14.44
NOX Emissions[1] (lb/mmBtu)	0.339	0.354	0.219
NOX Emissions TPY	8136.81	8496.85	5271.87
PM_{10} Fine Emissions[2] (lb/mmBtu)	0.00745	0.00745	0.00745
PM_{10} Fine Emissions (TPY)	178.82	178.82	179.34

[1]Baseline NOx emissions were based on the maximum 24-hr average emission rate (lb/hr) reported by each unit during the baseline period 2003-2005. 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]PM emissions are based on AP-42 emission factors for natural gas combustion (filterable and condensable).

Table 10: Source Parameters and Emissions for BART Control Options

Scenario		Control	Heat Input (mmBtu/hr)	NOX Emissions (lb/mmBtu)	NOX Emissions TPY
Control Option 1		LNB/OFA	5,480	0.254	6,097
	Natural Gas-Fired Unit 2	LNB/OFA	5,480	0.266	6,384
	Natural Gas-Fired Unit 3	LNB/OFA FGR	5,496	0.164	3,948
Control Option 2	Natural Gas-Fired Unit 1	LNB/OFA FGR	5,480	0.203	4,872
	Natural Gas-Fired Unit 2	LNB/OFA FGR	5,480	0.212	5,089
	Natural Gas-Fired Unit 3	LNB/OFA FGR	5,496	0.164	3,948

Scenario		Control	Heat Input (mmBtu/hr)	NOX Emissions (lb/mmBtu)	NOX Emissions TPY
Control Option 3	Natural Gas-Fired Unit 1	LNB/OFA + SCR	5,480	0.040	960
	Natural Gas-Fired Unit 2	LNB/OFA + SCR	5,480	0.040	960
	Natural Gas-Fired Unit 3	LNB/OFA + SCR	5,496	0.040	963

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 11: 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 12: CALPUFF Visibility Modeling Results for Seminole Units 1, 2 and 3

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	1.073	20	0.744	12	1.3	25	1.039	19
Caney Creek	1.173	18	0.455	7	0.443	7	0.69	11
Upper Buffalo	0.635	9	0.24	2	0.302	2	0.39	4
Hercules Glade	0.403	5	0.294	3	0.301	3	0.33	4
Scenario 2- Combustion Control- LNB/OFA/FGR								
Wichita Mountains	0.707	13	0.476	7	0.832	17	0.67	12
Caney Creek	0.754	12	0.284	1	0.284	2	0.44	5
Upper Buffalo	0.411	4	0.157	2	0.191	1	0.25	2
Hercules Glade	0.255	2	0.186	0	0.188	2	0.21	1

Modeling for SCR controls resulted in an approximately 80% reduction in visibility impairment from scenario two.

C. 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 three units at the Seminole Generating Station.

New LNB with OFA is determined to be BART for NOX control for Units 1-3 based, in part, on the following conclusions:

1. Installation of new LNB with OFA and FGR was cost effective, with a capital cost of $16,977,200 per unit for units 1 and 2 and $9,468,600 for unit 3 and an average cost effectiveness of $1,554-$2,120 per ton of NO_X removed for each unit over a twenty year operational life.

2. Combustion control using the LNB/OFA and FGR 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 0.203 lb/mmBtu for Unit 1, 0.212 lb/mmBtu for Unit 2 and 0.164 lb/mmBtu for Unit 3 are justified.

4. Annual NO_X emission reductions from new LNB with OFA and FGR on Units 1, 2, and 3 are 662-1,704 tons for a total annual reduction of 3,998 tons.

LNB with OFA and SCR was not determined to be BART for NO_X control for Units 1-3 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 and FGR. Additional capital costs for SCR on Units 1-3 are on average $89,957,200 per unit. Based on projected actual emissions, SCR could reduce overall NO_X emissions from Seminole Units 1, 2 and 3 by approximately 5,513 tpy (compared to combustion controls and flue gas recirculation); however, the incremental cost associated with this reduction is approximately $44,534,600 per year, or $8,078/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. SCR control may not be as effective on boilers that operate as peaking units, as NO_X reduction in an SCR is a function of flue gas temperature.

5. The cumulative visibility improvement for SCR, as compared to LNB/OFA and FGR across Wichita Mountains and Caney Creek (based on the 98th percentile modeled results) was 0.56-0.60 Δdv for all three units.

The Division considers the installation and operation of the BART determined NO_X controls, new LNB with OFA and FGR, to meet the statutory requirements of BART.

Unit-by-unit NO_X BART determinations:

Seminole Generating Station Unit 1: New LNB with OFA and FGR and meeting NO_X emission limit of 0.203 lb/mmBtu (30-day rolling average), 1,112 lb/hr (30-day rolling average), and 4,872 tpy (12-month rolling) as BART for NO_X.

Seminole Generating Station Unit 2: New LNB with OFA and FGR and meeting NO_X emission limit of 0.212 lb/mmBtu (30-day rolling average), 1,162 lb/hr (30-day rolling average), and 5,089 tpy (12-month rolling) as BART for NO_X.

Seminole Generating Station Unit 3: New LNB with OFA and FGR and meeting NO_X emission limit of 0.164 lb/mmBtu (30-day rolling average), 901 lb/hr (30-day rolling average), and 3,948 tpy (12-month rolling) as BART for NO_X.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)
Seminole 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 Seminole Station.

VI. OPERATING PERMIT

The Seminole 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 2 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
2-B	01	Unit 1 Boiler	5,480	1968
2-B	02	Unit 2 Boiler	5,480	1968
2-B	03	Unit 3 Boiler	5.496	5/28/70

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 NOX to below the emission limits below:

i. Low-NOX Burners,

ii. Overfire Air, and

iii. Flue Gas Recirculation.

e. The permittee shall maintain the combustion controls (Low-NOX burners, overfire air, and flue gas recirculation) 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#	NOX Emission Limit	Averaging Period
2-B	01	0.203 lb/MMBTU	30-day rolling
2-B	02	0.212 lb/MMBTU	30-day rolling
2-B	03	0.164 lb/MMBTU	30-day rolling

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

h. After installation of the BART, the affected facilities shall only be fired with natural gas.

i. 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 NOX, 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.

iii. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

Method 1: Sample and Velocity Traverses for Stationary Sources.

Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.

Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.

EXHIBIT B

Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis **January 15, 2010**

COMPANY:	**Oklahoma Gas and Electric**
FACILITY:	**Sooner Generating Station**
FACILITY LOCATION:	**Red Rock, Noble County, Oklahoma**
TYPE OF OPERATION:	**(2) 570 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).

Sooner Units 1 and 2 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, Sooner Units 1 and 2 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 Sooner Units 1 and 2 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains, Caney Creek and Upper Buffalo Class I Areas. Therefore, Sooner Units 1 and 2 were determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Sooner Units 1 and 2 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: Sooner Generating Station- Plant Operating Parameters for BART Evaluation

Parameter	Sooner Unit 1		Sooner Unit 2	
Plant Configuration	Pulverized Coal-Fired Boiler		Pulverized Coal-Fired Boiler	
Firing Configuration	Tangentially-fired		Tangentially-fired	
Gross Output (nominal)	570 MW		570 MW	
Maximum Input to Boiler	5,116 mmBtu/hr		5,116 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	3,075	0.601	2,988	0.584
SO_2	4,393	0.86	4,410	0.86
PM_{10}	194	0.038	200	0.039
Baseline Emissions (2004- 2006)				
Pollutant	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	1,834	0.384	1,561	0.337
SO_2	2,428	0.509	2,393	0.516

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 Sooner Units 1 & 2 (tangentially fired boilers firing subbituminous coal) is 0.15 lb/mmBtu.

Table 2: Proposed BART Controls and Limits

Unit	NO_X BART Emission Limit	BART Technology
Sooner Unit 1	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Sooner Unit 2	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Unit	**SO_2 BART Emission Limit**	**BART Technology**
Sooner Unit 1	0.65 lb/mmBtu (30-day average)	Low Sulfur Coal
	0.55 lb/mmBtu (annual average)	
Sooner Unit 2	0.65 lb/mmBtu (30-day average)	Low Sulfur Coal
	0.55 lb/mmBtu (annual average)	
Units 1 and 2	19,736 TPY	Low Sulfur Coal
Unit	**PM_{10} BART Emission Limit**	**BART Technology**
Sooner Unit 1	0.1 lb/mmBtu (3-hour average)	Electrostatic Precipitator
Sooner Unit 2	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 Sooner Units 1 and 2 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. Sooner units 1 and 2 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 Sooner Units 1 & 2, 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 Sooner 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 Sooner 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 Sooner, has not been demonstrated in practice. Assuming that SNCR could be installed on the Sooner 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 Sooner 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 Sooner Units 1 & 2.

Innovative NOX 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 Sooner Units 1 & 2. 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 Sooner Units 1 and 2. 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 Sooner 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 Sooner

Units 1 and 2. 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 Sooner 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 Sooner Boilers

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Sooner Station

Control Technology	Sooner Unit 1 Approximate NO_X Emission Rate (lb/mmBtu)	Sooner Unit 2 Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.07	0.07
LNB/OFA	0.15	0.15
Baseline	0.384	0.337

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 Sooner Units 1 and 2 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	Unit	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR
Control Equipment Capital Cost ($)	Unit 1	$14,055,900	$192,018,500
Annualized Capital Cost ($/Yr)	Unit 1	$1,206,100	$16,477,200
Annual O&M Costs ($/Yr)	Unit 1	$877,100	$14,487,400
Annual Cost of Control ($)	Unit 1	$2,083,200	$30,964,600

Table 6: Environmental Costs per Boiler

		Baseline	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu)	Unit 1	0.384	0.15	0.07
	Unit 2	0.337	0.15	0.07
Annual NO_X Emission (TPY)[1]	Unit 1	7,266	3,025	1,412
	Unit 2	5,689	3,025	1,412
Annual NO_X Reduction (TPY)	Unit 1	--	4,241	5,854
	Unit 2	--	2,664	4,277
Annual Cost of Control	Unit 1	--	$2,091,800	$30,795,600
	Unit 2	--	$2,091,800	$30,795,600
Cost per Ton of Reduction	Unit 1	--	$493	$5,260
	Unit 2	--	$785	$7,200
Incremental Cost per ton of Reduction[2]	Unit 1	--	--	$17,795
	Unit 2	--	--	$17,795

(1) Emissions for the BART analysis are based on average heat inputs of 4,771 and 4,634 mmBtu/hr for Units 1 & 2. Annual emissions were calculated assuming 7,738 and 7,164 hours/year per for Units 1 and 2 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 Sooner Units 1 and 2 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. Sooner Units 1 & 2 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.

Sooner Units 1 & 2 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 Sooner Units 1 & 2.

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 Sooner Units 1 & 2 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.

Wet Lime Scrubbing

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 SO_2 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.

Wet Limestone Scrubbing

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. WESP has not been widely used in utility applications, and has only been proposed on boilers firing high sulfur coals and equipped with SCR. Sooner Units 1 & 2 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 Sooner Units 1 & 2 will only be approximately 5ppm. This emission rate does not take into account inherent acid gas removal associated with alkalinity in the subbituminous 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 Sooner Units 1 & 2, 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. The 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 Sooner Units 1 & 2. 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 Sooner Units 1 & 2, 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 Sooner Units 1 & 2, 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- Sooner Station

Control Technology	Sooner Unit 1 Approximate SO_2 Emission Rate (lb/mmBtu)	Sooner Unit 2 Approximate SO_2 Emission Rate (lb/mmBtu)
Wet FGD	0.08	0.08
Dry **FGD**- Spray **Dryer Absorber**	0.10	0.10
Baseline	0.86	0.86
Annual Average Baseline	0.509	0.516

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 Sooner Units 1 and 2 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 Sooner facility. In degree of difficulty, the retrofit at the Sooner 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 Sooner 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 Sooner 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)	2014
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 $584,589,400 which is $196,222,600 less than the CUECost derived estimates provided in 2008. 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 30,281,800 per boiler, which is $3,219,100 per boiler per year less 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, \$118.80/ton, which is 59% of the previously assumed cost. Water costs were based on 205,256 lb/hr at full load, a 90% capacity factor and \$0.49/1000 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 \$39.60/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 \$3.22/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 \$83.83/MWh, which is 186% of the previously assumed power cost.

Increases in FGD waste disposal, bag and cage replacement, and auxiliary power costs offset decreases in water and lime reagent costs resulting in no appreciable change in expected variable O&M costs from the 2008 estimate.

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 57.33/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 \$11,456,200 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 0.60% 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 $12,636,500 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 1 and 2 - Dry FGD- Spray Dryer Absorber

Cost	Unit 1	Unit 2
Total Capital **Investment** ($)	$292,294,900	$292,294,900
Total Capital **Investment** ($/kW)	**$514**	**$514**
Capital **Recovery Cost** ($/Yr)	$30,281,800	$30,281,800
Annual O&M Costs ($/Yr)	**$**16,550,500	**$**16,550,500
Total Annual Cost ($)	$46,832,300	$46,832,300

Table 11: Environmental Costs for Units 1 and 2- Dry FGD- Spray Dryer **Absorber**

	Unit 1	Unit 2
SO_2 **Baseline** (TPY)[1]	**9,394**	8,570
SO_2 **Controlled (lb/mmBtu)**	0.1	**0.1**
Annual SO_2 **Controlled** (TPY)[2]	**2,017**	2,017
Annual SO_2 **Reduction** (TPY)	**7,377**	6,553
Total Annual Cost ($)	**$46,832,300**	$46,832,300
Cost per Ton of Reduction	**$6,348**	**$7,147**

[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 5,116 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 2- Wet FGD

Cost	OG&E Cost Estimates	
	Unit 1	Unit 2
Total Capital Investment ($)	$441,658,000	$441,658,000
Total Capital Investment ($/kW)	$775	$775
Capital Recovery Cost ($/Yr)	$37,898,900	$37,898,900
Annual O&M Costs ($/Yr)	$16,550,500	$16,550,500
Total Annual Cost ($)	$54,449,400	$54,449,400
Control SO_2 Emission Rate (lb/mmBtu)	0.08	0.08
Baseline Annual Emissions (TPY)[1]	9,394	8,570
Controlled Annual SO_2 Emission (TPY)[2]	1,613	1,613
Annual SO_2 Reduction (TPY)	7,781	6,957
Cost per Ton of Reduction ($/Ton)	$6,998	$7,827
Incremental Annual Cost ($/Ton)	$18,854	$18,854

(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 5,116 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). Sooner Units 1 & 2 are currently equipped with ESP control systems.

Table 12: 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	0.039	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 Sooner 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 Sooner 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 Sooner Generating Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Sooner 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.

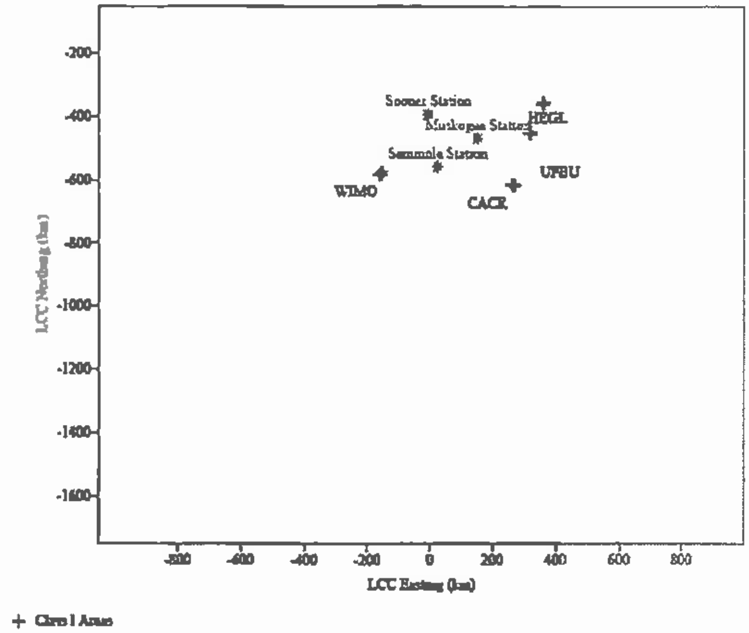

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING

Because of the results of the applicants screening modeling for the Sooner 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 Sooner 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 13: 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 14: 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, 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

Variable	Description	Value
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.

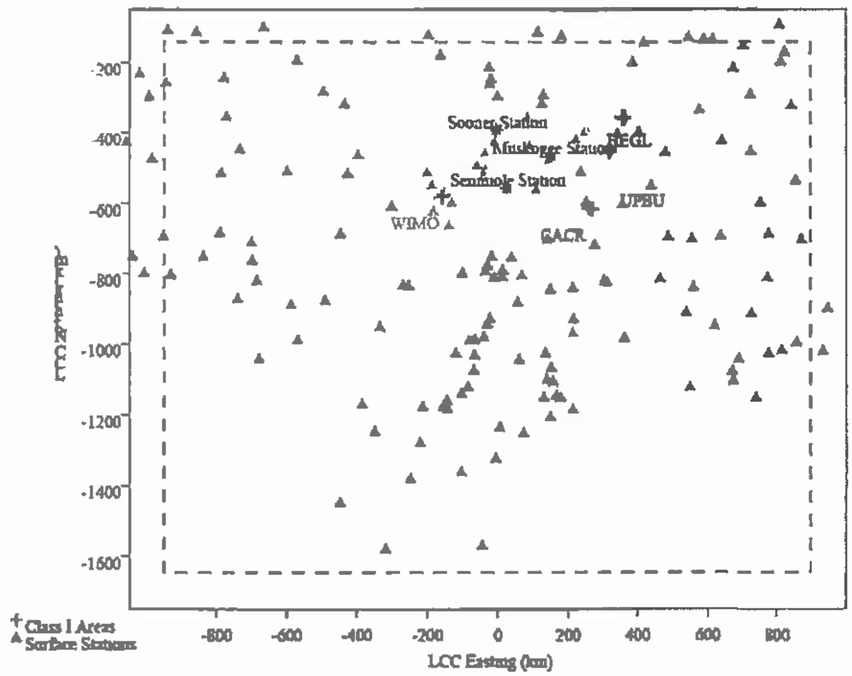

Figure 2: Plot of surface station locations

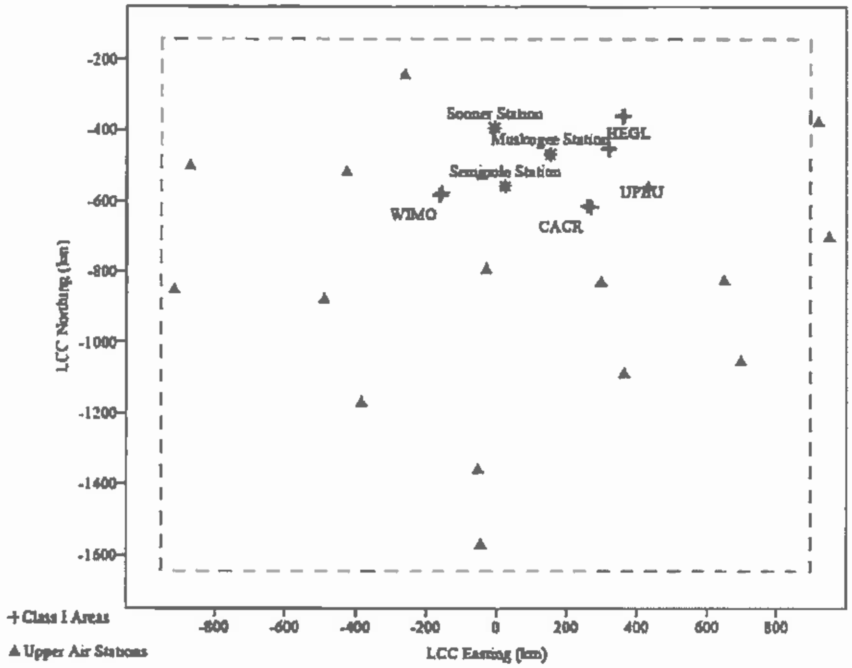

Figure 3: Plot of upper air station locations

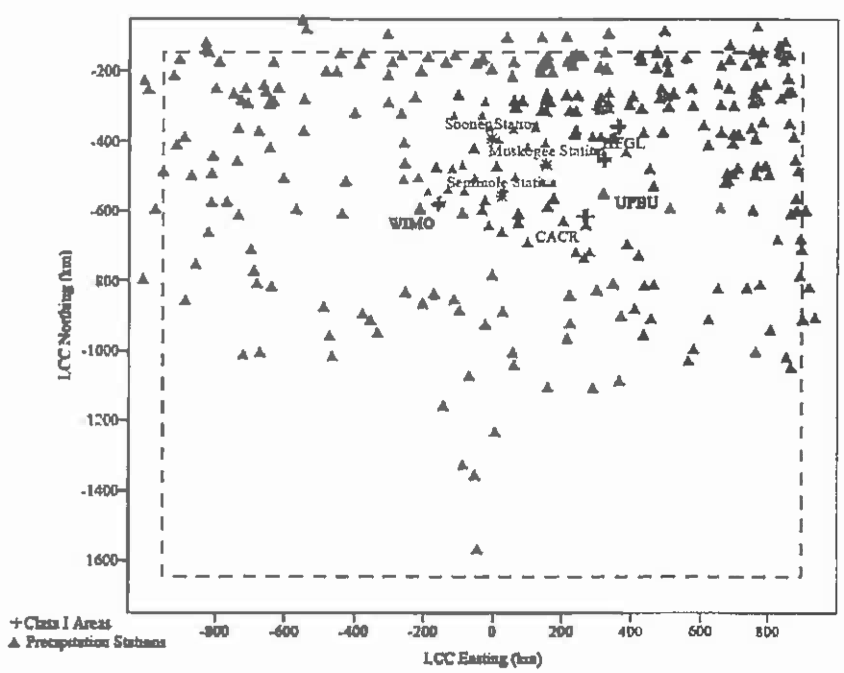

Figure 4. Plot of precipitation observation stations

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 15: Source Parameters

Parameter	Baseline[1]	
	Coal-Fired Unit 1	Coal-Fired Unit 2
Heat Input (mmBtu/hr)	5,116	5,116
Stack Height (m)	152.44	152.44
Stack Diameter (m)	6.10	6.10
Stack Temperature (K)[2]	430.78	430.78
Exit Velocity (m/s)[2]	34.12	34.12
Baseline SO_2 Emissions (lb/mmBtu)	0.86	0.86
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)	0.601	0.584
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)	0.0379	0.0391
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 30.61 m/s. For WFGD, stack temperature decreased to 331.89K and velocity decreased to 28.35 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 16: 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 17: CALPUFF Visibility Modeling Results for Sooner Units 1 and 2- 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	1.244	19	0.901	16	1.199	25	1.115	20
Caney Creek	0.577	10	0.404	5	0.541	10	0.507	8
Upper Buffalo	0.573	8	0.335	4	0.337	3	0.415	5
Hercules Glade	0.440	6	0.274	5	0.388	1	0.367	4
Scenario 1- Combustion Control- LNB/OFA								
Wichita Mountains	0.309	0	0.236	1	0.308	0	0.284	0
Caney Creek	0.147	0	0.103	0	0.14	0	0.13	0
Upper Buffalo	0.139	0	0.085	0	0.084	0	0.103	0
Hercules Glade	0.109	3	0.064	1	0.095	3	0.089	2

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

Table 18: CALPUFF Visibility Modeling Results for Sooner Units 1 and 2- SO_2

Class I Area	2001 98th Percentile Value (Δdv)	2001 No. of Days > 0.5 Δdv	2002 98th Percentile Value (Δdv)	2002 No. of Days > 0.5 Δdv	2003 98th Percentile Value (Δdv)	2003 No. of Days > 0.5 Δdv	3-Year Average 98th Percentile Value (Δdv)	3-Year Average No. of Days > 0.5 Δdv
Baseline								
Wichita Mountains	1.224	24	1.081	24	1.792	33	1.366	27
Caney Creek	0.709	11	0.505	10	0.584	11	0.599	11
Upper Buffalo	0.534	10	0.357	4	0.43	5	0.440	6
Hercules Glade	0.423	5	0.267	2	0.34	3	0.343	3
Scenario 1- Dry FGD								
Wichita Mountains	0.169	3	0.141	0	0.219	3	0.176	2
Caney Creek	0.08	0	0.062	0	0.063	0	0.068	0
Upper Buffalo	0.051	0	0.045	0	0.043	0	0.046	0
Hercules Glade	0.05	0	0.033	0	0.037	0	0.04	0

While mass emissions are decreased marginally with Wet FGD controls modeled impacts increase over modeled concentrations in scenario one. This 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 Sooner Generating Station.

NO_X

New LNB with OFA is determined to be BART for NO_X control for Units 1 and 2 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective, with a capital cost of $14,055,900 per unit for units 1 and 2 and an average cost effectiveness of $493-785 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 1 and 2 are justified meet the presumptive limits prescribed by EPA.

4. Annual NO_X emission reductions from new LNB with OFA on Units 1 and 2 are 2,664-4,241 tons for a total annual reduction of 6,905 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 1 and 2 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 1 and 2 are on average $192,018,500 per unit. Based on projected emissions, SCR could reduce overall NO_X emissions from Sooner Units 1 and 2 by approximately 3,226 TPY beyond combustion controls; however, the incremental cost associated with this reduction is approximately $17,795/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 0.15 Δdv for both units.

SO_2

Continued use of low sulfur coal is determined to be BART for SO_2 control for Units 1 and 2 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 Sooner facility. The final estimate for both boilers at $584,589,800 is $175,329,800 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 lower than the cost of controlling a single boiler at the Sooner facility ($292,294,700). 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 Sooner for DFGD is $6,348-$7,147 per ton of SO_2 removed for each unit over a twenty year operational life. The cost of this control at the Sooner 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 Sooner Facility was anticipated to reduce impairment by 2.44 dv. Importantly, the cost effectiveness of that improvement is now calculated to be $38,387,000/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 Sooner station is located with 300 km of 1 Class I area. 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 10.4 times more cost effective than DFGD controls at the Sooner 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 Sooner 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 Sooner 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 1 and 2 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 Sooner Units 1 and 2 by approximately 808 TPY beyond dry scrubbers; however, the incremental cost associated with this reduction is approximately $18,854/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.

PM_{10}

The existing ESP control is determined to be BART for PM_{10} controls for Units 1 and 2 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 1	Unit 2
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	767 lb/hr (30-day rolling average),	767 lb/hr (30-day rolling average),
Emission Rate TPY	3,361 TPY (12-month rolling)	3,361 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	3,325 lb/hr (30-day rolling average)	3,325 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	19,736 TPY	
PM_{10} Control	Existing ESP	Existing ESP
Emission Rate (lb/mmBtu)	0.1 lb/mmBtu	0.1 lb/mmBtu
Emission Rate lb/hr	512 lb/hr	512 lb/hr
Emission Rate TPY	2,241 TPY (12-month rolling average)	2,241 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 Sooner Units 1 and 2 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 1	Unit 2
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	512 lb/hr (30-day rolling average)	512 lb/hr (30-day rolling average)
Emission Rate TPY	2,241 TPY	2,241 TPY
PM_{10} Control	Fabric Filter	Fabric Filter
Emission Rate (lb/mmBtu)	0.015 lb/mmBtu	0.015 lb/mmBtu
Emission Rate lb/hr	77 lb/hr	77 lb/hr
Emission Rate TPY	336 TPY (12-month rolling average)	336 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 an achievable 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 1 areas can be preserved for the long term 2064 goal of natural visibility.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)
Sooner 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 Sooner Station. The permit application should contain PM_{10} and $PM_{2.5}$ emission estimates for filterable and condensable emissions.

VI. OPERATING PERMIT

The Sooner 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 2 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
2-B	01	Unit 1 Boiler	5,116	1974
2-B	02	Unit 2 Boiler	5,116	1974

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) 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
2-B	01	0.15 lb/mmBtu	0.65 lb/mmBtu	30-day rolling
2-B	02	0.15 lb/mmBtu	0.65 lb/mmBtu	30-day rolling

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

EU ID#	Point ID#	SO_2 Emission Limit	SO_2 Emission Limit	Averaging Period
2-B	01	19,736	0.55 lb/mmBtu	Annual rolling
2-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.

EXHIBIT C

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.

Wet Lime Scrubbing

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.

Wet Limestone Scrubbing

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

Cost	OG&E Cost Estimates	
	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.

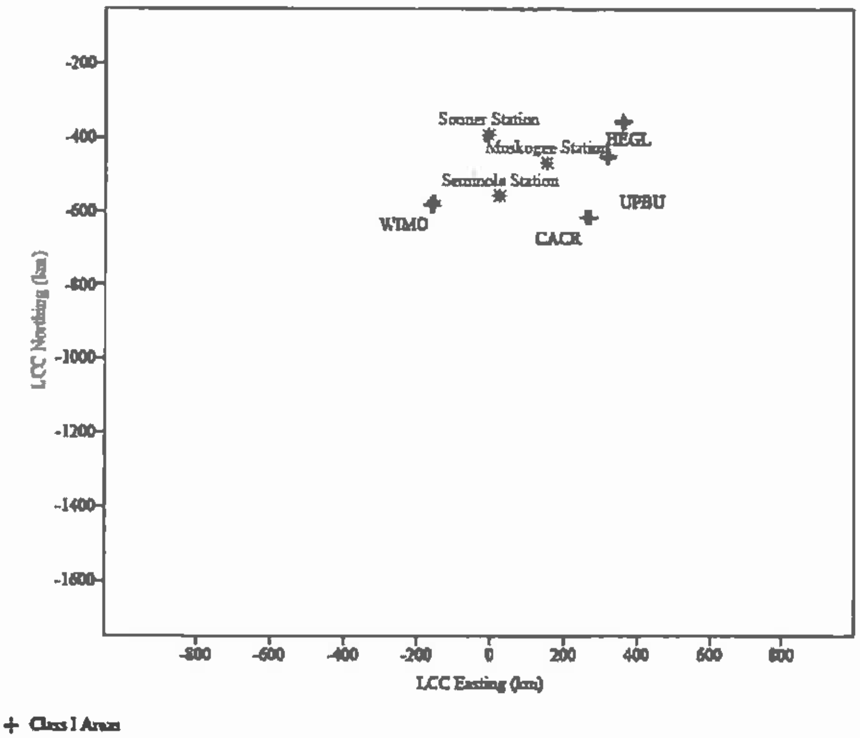

Figure 1: Plot of Facility location in relation to nearest Class I areas

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.

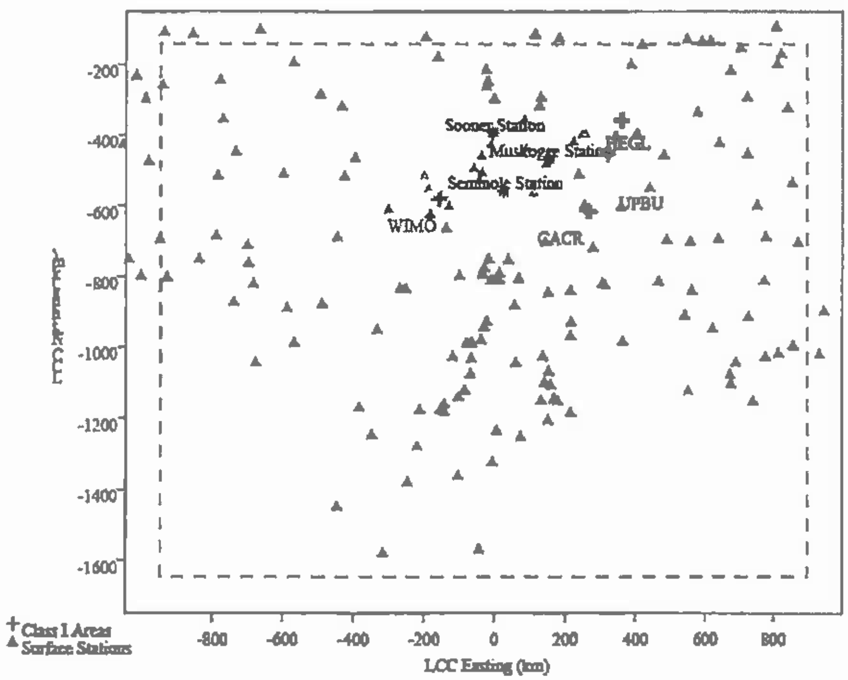

Figure 2: Plot of surface station locations

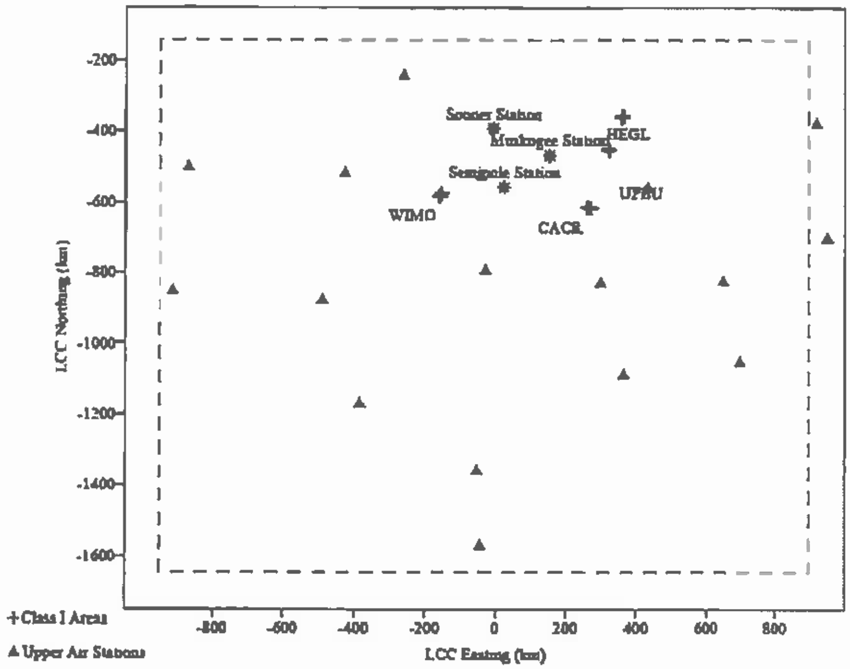

Figure 3: Plot of upper air station locations

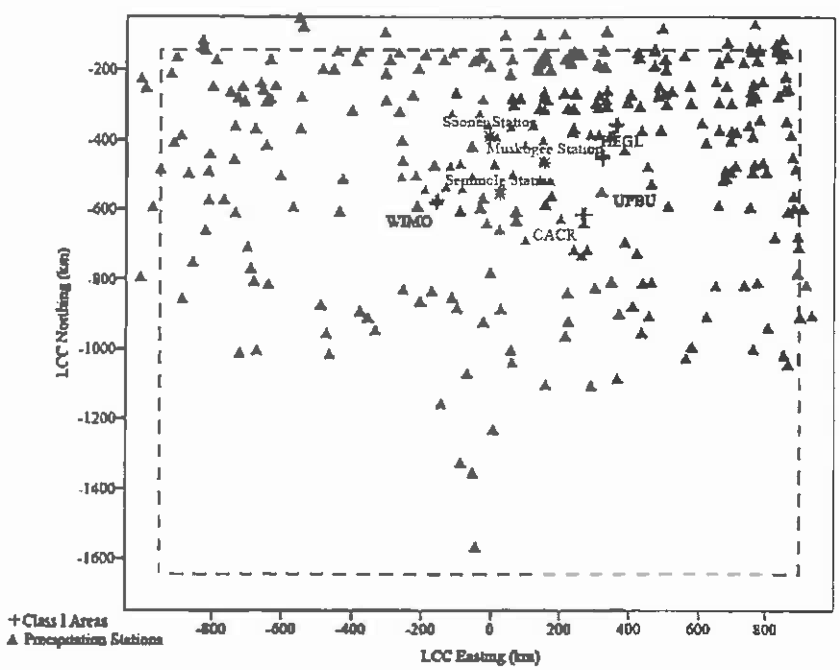

Figure 4. Plot of precipitation observation stations

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

Parameter	Baseline[1] Coal-Fired Unit 4	Baseline[1] 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 1 and 2 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 1 and 2 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 with 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 3 and 4 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.

Item 2 of Appendix 6-5

AEP-PSO Regional Haze Agreement

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

IN THE MATTER OF: **Public Service Company of Oklahoma,** **Comanche Power Station,** **Southwestern Power Station,** **Northeastern Power Station,**	**CASE NO. 10-025**

OKLAHOMA
DEPT. OF ENVIRONMENTAL QUALITY

FEB 17 2010

FILED BY: Dmcoy
HEARING CLERK

REGIONAL HAZE AGREEMENT

The parties to this Agreement, the Oklahoma Department of Environmental Quality ("DEQ") and the Public Service Company of Oklahoma ("PSO") hereby agree to the entry of this Regional Haze Agreement ("Agreement") in order to satisfy the Best Available Retrofit Technology ("BART") requirements associated with the Regional Haze Rule, 40 C.F.R. Subpart P, and 40 C.F.R. Part 51, Appendix Y (incorporated by reference at OAC 252:100-8-72).

FINDINGS OF FACT

1. PSO is an Oklahoma corporation with its principal headquarters in Tulsa, Oklahoma.

2. PSO owns and operates the following three (3) fossil-fuel fired steam electric generating plants that are BART eligible:

> Comanche Power Station – This station is located in Comanche County, Oklahoma. The station includes two (2) 94 megawatts ("MW") combustion turbine generating units designated as Comanche Units 1 and 2. Both units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Each unit is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr and each unit fires natural gas as its primary fuel. Because the units fire natural gas, there are no sulfur dioxide ("SO2") or particulate matter ("PM") emission control systems. Both units have the potential to emit 250 tons per year ("TPY") of NOx. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-261-TVR, which was issued on April 27, 2006.

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

IN THE MATTER OF:	
Public Service Company of Oklahoma, Comanche Power Station, Southwestern Power Station, Northeastern Power Station,	CASE NO. 10-025

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> <u>Comanche Power Station</u> – This station is located in Comanche County, Oklahoma. The station includes two (2) 94 megawatts ("MW") combustion turbine generating units designated as Comanche Units 1 and 2. Both units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Each unit is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr and each unit fires natural gas as its primary fuel. Because the units fire natural gas, there are no sulfur dioxide ("SO2") or particulate matter ("PM") emission control systems. Both units have the potential to emit 250 tons per year ("TPY") of NOx. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-261-TVR, which was issued on April 27, 2006.

Southwestern Power Station – This station is located in Caddo County, Oklahoma. The station includes one (1) 332 MW steam electric generating unit designated as Southwestern Unit 3. The unit is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr. The unit was in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. The unit fires natural gas as its primary fuel. Because the unit fires natural gas, there are no SO2 or PM emission control systems. The unit has the potential to emit 250 TPY of NOx. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-403-TVR (M-3), which was issued on July, 20, 2008.

Northeastern Power Station – This station is located in Rogers County, Oklahoma. The station includes one (1) 495 MW gas-fired steam electric generating unit designated as Northeastern Unit 2 and two (2) 490 MW coal-fired steam electric generating units designated as Northeastern Units 3 and 4. All three (3) units are fossil-fuel fired boilers with heat inputs greater than 250-mmBtu/hr. All three (3) units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Northeastern Unit 2 fires natural gas as its primary fuel; consequently, it has no SO2 or PM emission control systems. Unit 2 has the potential to emit 250 TPY of NOx. Northeastern Units 3 and 4 both fire coal as their primary fuel, and both units have the potential to emit 250 TPY or more of NOx, SO2, and PM. The facility is currently permitted to operate under DEQ Air Quality Permit No. 2003-410-TVR, which was issued on February 4, 2009.

3. In 1977, the U.S. Congress enacted § 169 of the federal Clean Air Act, 42 U.S.C. § 7491, to protect the visibility of Class I Federal areas (areas determined to be of great scenic importance) from impairment. A particular type of visibility impairment is referred to as "Regional Haze." *See* 40 C.F.R. § 51.301 ("*Regional Haze* means visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources."). The federal Clean Air Act requires the development of emission limitations for pollutants contributing to Regional Haze which emanate from a variety of sources, including fossil-fuel fired electric generating power plants having a total energy generating capacity in excess of 750 MW.

4. In 1980, the U.S. Environmental Protection Agency ("EPA") promulgated regulations addressing Regional Haze reasonably attributable to specific sources or small groups of sources. *See* 40 Fed.Reg. 80,084. The regulations required States to determine which sources impair visibility and require the installation of BART on certain of those sources.

5. In 1999, EPA amended 40 C.F.R. Part 51, Subpart P, to further define the facilities subject to the Regional Haze requirements. The regulations require States to develop and implement long-term strategies for reducing air pollutants that cause or contribute to visibility impairment in Class I Federal areas.

6. On July 6, 2005, the EPA published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule"). *See* 70 Fed.Reg. 39104. The federal Clean Air Act, 42 U.S.C. §§ 7401 *et seq.*, and the Regional Haze Rule, 40 C.F.R. §§ 51.300 – 51.309, require certain States, including Oklahoma, to make reasonable progress toward the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas." 42 U.S.C. §§ 7491(a)(1), (b)(2) and 40 C.F.R. § 51.300. Moreover, the Regional Haze Rule requires the State of Oklahoma to develop programs to "address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State which may be affected by emissions from within the State." 40 C.F.R. § 51.308(d); *see also* 40 C.F.R. § 51.300(b).

7. In order to meet the requirements of the Regional Haze Rule, States must submit State Implementation Plans ("SIP") implementing the requirements of the Regional Haze Rule to EPA for approval. *See id.* The States were required to submit their SIPs prior to December 17, 2007. *See* 40 C.F.R. § 51.308(b). Each Regional Haze SIP must contain "emission limitations

representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area . . . ." *See* 40 C.F.R. § 51.308(e).

8. 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-fired boilers of more than 250 mmBtu/hr heat input). *See* OAC 252:100-8-71, 40 C.F.R. Part 51, Appendix Y(I)(C)(1), *and* 42 U.S.C. § 7491(b)(2)(A).

9. "Air pollutants emitted by sources in Oklahoma which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I federal area are NOx, SO2, PM-10, and PM-2.5." OAC 252:100-8-73(b).

10. As stated in Paragraph 2 above, Comanche Units 1 and 2, Southwestern Unit 3, and Northeastern Units 2, 3, and 4, are all: fossil fuel-fired steam electric plants with heat inputs greater than 250 mmBtu/hr; units that were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962; and, based on a review of existing emissions data, units that have the potential to emit more than 250 tons per year of a visibility impairing pollutant. Consequently, all six (6) units meet the definition of a BART-eligible source.

11. 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. *See* OAC 252:100-8-73(a), 42 U.S.C. § 7491(b)(2)(a), *and* 40 C.F.R. § 51.308(e). EPA 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. *See* 40 C.F.R. Part 51, Appendix Y(III)(A)(1); *see also* 70 Fed.Reg. 39,120; *and* OAC 252:100-8-73(a). Visibility impact modeling indicates that the maximum predicted visibility impacts from all six (6) of the PSO units listed in Paragraph 2 above exceed the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. *See* State of Oklahoma Regional Haze SIP, p. 72, table VI-4. Therefore, all six (6) units are subject to the BART determination requirements.

12. Since the Comanche Power Station, the Southwestern Power Station, and the Northeastern Power Station have a total generating capacity in excess of 750 MW, the Appendix Y guidelines were used to prepare BART determinations for each station. Based on an evaluation of potentially feasible retrofit control technologies, including an assessment of the costs and visibility improvements associated therewith, the following control technologies and emission limits as described in the BART Determinations for each of the three (3) stations (attached as Exhibits A, B, and C; collectively "BART Determinations") have been determined to be BART and shall be implemented within 5 years of EPA's approval of Oklahoma's Regional Haze SIP:

<u>Comanche Power Station</u> -

Control	**Unit 1**	**Unit 2**
NO_X Control	Dry Low-NO_X Burners	Dry Low-NO_X Burners
NOx Emission Rate (lb/mmBtu)	0.15 lb/mmBtu (30-day average)	0.15 lb/mmBtu (30-day average)

<u>Southwestern Power Station</u> -

Control	**Unit 3**
NO_X Control	LNB with OFA
NOx Emission Rate (lb/mmBtu)	0.45 lb/mmBtu (30-day rolling average)

<u>**Northeastern Power Station**</u> -

Control	Unit 2	Unit 3	Unit 4
NO_X Control	LNB with OFA	LNB with OFA	New LNB with OFA
Emission Rate (lb/mmBtu)	0.28 lb/mmBtu (30-day rolling average)	0.15 lb/mmBtu (30-day rolling average)	0.15 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	1331 lb/hr (30-day rolling average)	716 lb/hr (30-day rolling average)	716 lb/hr (30-day rolling average)
Emission Rate TPY	5,830 TPY (12-month rolling)	6,274 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	--	3,104 lb/hr (30-day rolling average)	3,104 lb/hr (30-day rolling average)
Emission Rate (lb/mmBtu)	--	0.55 lb/mmBtu (12-month rolling average)	0.55 lb/mmBtu (12-month rolling average)
Emission Rate (TPY)		23,006 TPY	
PM_{10} Control[1]	--	ESP	ESP
Emission Rate (lb/mmBtu)	--	0.1 lb/mmBtu (3-hour rolling average)	0.1 lb/mmBtu (3-hour rolling average)
Emission Rate lb/hr	--	478 lb/hr (3-hour rolling average)	478 lb/hr (3-hour rolling average)
Emission Rate TPY	--	4,183 TPY (12-month rolling average)	

[1]Current emissions limits for ESPs are based on minimum NSPS requirements for front half catch. As part of the permitting process, PSO will be required to propose emission limits for front and back half reflective of the control technology and consistent with performance test results.

13. In the event that: (i) EPA disapproves the DEQ determination described in the BART Determinations that Dry-Flue Gas Desulfurization with Spray Dryer Absorber ("Dry FGD with SDA") is not cost-effective for SO2 control; and (ii) all administrative and judicial appeals of EPA's disapproval have been exhausted, then the low-sulfur coal requirement in Paragraph 12 and

the BART Determinations for SO2 shall be replaced with a requirement that Northeastern Units 3 and 4 shall, at the election of the owner and operator of the Unit, either: (i) install Dry FGD with SDA or meet the corresponding SO2 emission limits listed below (and further described in the Contingent BART Determination, *see* § IV(F) of Exhibit C) by January 1, 2018; or (ii) comply with the approved alternative described in Paragraph 14 prior to December 31, 2026:

Northeastern Power Station -

Control	**Unit 3**	**Unit 4**
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	478 lb/hr (30-day rolling average)	478 lb/hr (30-day rolling average)
Emission Rate TPY	2,091 TPY (12-month rolling average)	2,091 TPY (12-month rolling average)

14. In lieu of installing and operating BART for SO2 control at the two (2) coal fired units (i.e., Northeastern Units 3 and 4), PSO may elect to implement the fuel switching alternative approved pursuant to 40 C.F.R. § 51.308(e)(2) and as part of the long-term strategy in fulfillment of 40 C.F.R. § 51.308(d)(3). *See* Greater Reasonable Progress Alternative Determination, § IV(G) of Exhibit C). As detailed in the Alternative Determination, implementation of this alternative requires PSO to achieve by December 31, 2026 a combined annual SO2 emission limit that is equivalent to: (i) the SO2 emission limits provided in Paragraph 13 for installing and operating Dry FGD with SDA on one (1) of these coal-fired units; and (ii) being at or below the SO2 emissions that would result from switching the other one (1) coal-fired unit to natural gas. By adopting the emission limits described in the previous sentence, DEQ and PSO expect the cumulative SO2 emissions from Northeastern Units 3 and 4 to be approximately seven percent (43 %) less than would be achieved through the installation and operation of Dry FGD with SDA at both units. *See*

Alternative Determination. If PSO has elected to comply with the emission limits provided in this Paragraph 14 and if, prior to January 1, 2022, any of these units is required by any environmental law other than the Regional Haze Rule to install flue gas desulfurization equipment or achieve an SO2 emissions rate lower than 0.10 lb/mmBtu, and if PSO proceeds to take all necessary steps to comply with such legal requirement, the enforceable emission limits adopted pursuant to this Paragraph 14 in the operating permits for the affected coal units shall be adjusted, with the reasonable consent of DEQ and PSO, as appropriate to reflect the installation of that equipment or the emission rates specified under such legal requirement.

15. PSO and DEQ agree that it is beneficial to resolve this matter promptly and by agreement.

16. PSO and DEQ waive the filing of a petition or other pleading, and PSO waives the right to a hearing.

CONCLUSIONS OF LAW

17. DEQ has regulatory jurisdiction and authority in this matter, and PSO is subject to the jurisdiction and authority of DEQ under Oklahoma law, 27A Okla. Stat. ("O.S.") §§ 2-5-101 to -118, and the rules promulgated thereunder at Oklahoma Administrative Code ("OAC"), Title 252, Chapter 100, Air Pollution Control. This Order is executed under the authority of, and in conformity with, 27A O.S. § 2-5-110(G).

18. PSO and DEQ are authorized by 75 O.S. § 309(E) and 27A O.S. § 2-3-506(B) to resolve this matter by agreement.

19. "Air pollutants emitted by sources in Oklahoma which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I federal area are NOx, SO2, PM-10, and PM-2.5." OAC 252:100-8-73(b).

20. DEQ administrative rules provide that BART applicability "shall be determined using the criteria in Section III of Appendix of 40 CFR 51 in effect on July 6, 2005." OAC 252:100-8-73(a); *see also* OAC 252:100-8-72 ("Appendix Y, Guidelines for BART Determinations Under the Regional Haze Rule, of 40 CFR 51 is hereby incorporated by reference as it exists July 6, 2005."). Similarly, the corresponding Federal regulations provide, "[t]he determination of BART for fossil fuel-fired power plants having a total generating capacity greater than 750 megawatts [MW] must be made pursuant to the guidelines in appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule)." *See* 40 C.F.R. § 51.308(e)(1)(ii)(B); see *also* 42 U.S.C. § 7491(b)(2)(B). As described in Paragraph 2 of the Statement of Facts, each of the Comanche Power Station, Southwestern Power Station, and Northeastern Power Station, has a total generating capacity greater than 750 MW and, therefore, the BART determinations for each of these stations must be made pursuant to the "Guidelines for BART Determinations Under the Regional Haze Rule."

21. State and Federal rules define BART-eligible sources to 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-fired boilers of more than 250 mmBtu/hr heat input). *See* OAC 252:100-8-71, 40 C.F.R. Part 51, Appendix Y(I)(C)(1), *and* 42 U.S.C. § 7491(b)(2)(A). As stated in Paragraphs 2 and 10 of the Statement of Facts, Comanche Units 1 and 2, Southwestern Unit 3, and Northeastern Units 2, 3, and 4 meet all three (3) criteria listed above and, therefore, meet the definition of a BART eligible source.

22. OAC 252:100-8-73(a) provides in part:

> Each BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area is subject to BART. This shall be determined using the criteria in Section III of Appendix Y of 40 CFR 51 in effect on July 6, 2005. Thresholds for visibility impairment are set forth in OAC 252:100-8-73(a)(1) and (2).
>
> (1) A source that is responsible for an impact of 1.0 deciview or more is considered to cause visibility impairment.
>
> (2) A source that causes an impact greater than 0.5 deciviews contributes to visibility impairment.

As stated in Paragraph 11 of the Statement of Facts, Comanche Units 1 and 2, Southwestern Unit 3, and Northeastern Units 2, 3, and 4, each contribute greater than 0.5 deciviews to visibility impairment at the Wichita Mountains Class I Area and, therefore, are considered subject to BART.

23. OAC 252:100-8-75(e) provides that "[t]he owner or operator of each BART-eligible source subject to BART shall install and operate BART no later than five years after EPA approves the Oklahoma Regional Haze SIP." Similarly, the Federal rule states that each Regional Haze SIP must contain "[a] requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision." 40 C.F.R. § 51.308(e)(1)(iv).

24. In lieu of installing and operating BART, the Federal rules provide that States may allow sources subject to BART to implement an alternative demonstrated to "achieve greater reasonable progress toward natural visibility conditions." *See* 40 C.F.R. § 51.308(e). Any approved Greater Reasonable Progress Alternative shall comply with the requirements of 40 C.F.R. § 51.308(e)(2).

25. In addition to the BART requirements, the Federal rules give States authority to adopt "emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals" as part of the long-term strategy that addresses regional haze visibility impairment. *See* 40 C.F.R. § 51.308(d)(3).

AGREEMENT

26. Based on the above paragraphs, PSO and the DEQ agree, and it is ordered by the Executive Director as follows:

A. PSO, at its election, shall either: (i) install and operate BART and achieve the related emission limits at the Comanche Power Station, the Southwestern Power Station, and the Northeastern Power Station as set forth in Paragraph 12 and the corresponding BART Determinations, within 5 years of EPA's approval of Oklahoma's Regional Haze SIP; or (ii) implement the approved Greater Reasonable Progress Alternative (i.e., natural gas fuel switching alternative) described in Paragraph 14 and the Alternative Determinations by December 31, 2026.

B. In the event that EPA disapproves the DEQ determination that Dry FGD with SDA is not cost-effective for SO2 control at Northeastern Units 3 and 4 and such disapproval is upheld after all judicial and/or administrative appeals have been exhausted, the SO2 related portions of the BART Determinations and the related SO2 emission limits set forth in Paragraph 12 shall not have any further force or effect, and PSO, at its election, shall either: (i) achieve the SO2 emission limits at the Northeastern Units 3 and 4 on or before January 1, 2018 as set forth in Paragraph 13 and the corresponding Contingent BART Determinations; or (ii) implement the approved Greater Reasonable Progress Alternative (i.e., natural gas fuel switching alternative) on or before December 31, 2026 as set forth in Paragraph 14 and the Alternative Determination.

27. Any control equipment required to be installed as BART shall be properly operated and maintained. *See* 40 C.F.R. § 51.308(e)(v).

28. Nothing in this Agreement shall constitute or be construed as a release for any claim or cause of action related to any NSR or New Source Performance Standard ("NSPS") liability under the Clean Air Act or the rules promulgated thereunder.

29. The emission limits required by this Agreement shall be incorporated into any otherwise required construction or operating permit issued to PSO for the affected units.

30. This Agreement shall be incorporated into the Regional Haze State Implementation Plan submitted to EPA for approval by the State of Oklahoma.

GENERAL PROVISIONS

31. PSO agrees to perform the requirements of this Agreement within the time frames specified unless performance is prevented or delayed by events which are a "force majeure." For purposes of this Agreement, a force majeure event is defined as any event arising from causes beyond the reasonable control of PSO or PSO's contractors, subcontractors or laboratories which delays or prevents the performance of any obligation under this Agreement. Examples are vandalism; fire; flood; labor disputes or strikes; weather conditions which prevent or seriously impair construction activities; civil disorder or unrest; and "acts of God." Force majeure events do *not* include increased costs of performance of the tasks agreed to in this Agreement, or changed economic circumstances. PSO must notify DEQ in writing within thirty (30) days after PSO knows or should have known of a force majeure event that is expected to cause a delay in achieving compliance with any requirement of this Agreement. Failure to submit notification within thirty (30) days waives the right to claim force majeure.

32. No informal advice, guidance, suggestions or comments by employees of DEQ regarding reports, plans, specifications, schedules, and other writings affect PSO's obligation to obtain written approval by DEQ, when required by this Agreement.

33. Unless otherwise specified, any report, notice or other communication required under this Agreement must be in writing and must be sent to:

For the Department of Environmental Quality:

Eddie Terrill, Director
Air Quality Division
P.O. Box 1677
Oklahoma City, OK 73101-1677

With copies to:

Robert D. Singletary
Environmental Attorney Supervisor
Oklahoma Department of Environmental Quality
Office of General Counsel
P.O. Box 1677
Oklahoma City, OK 73101-1677

Lee Warden, Environmental Engineering Manager
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

For PSO:

Howard L. (Bud) Ground
Manager State and Governmental & Environmental Affairs
Public Service Company of Oklahoma
1601 Northwest Expressway, Suite 1400
Oklahoma City, OK 73118

With copies to:

Janet Henry
Associate General Counsel
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

34. This Agreement is enforceable as a final order of the Executive Director of DEQ. DEQ retains jurisdiction of this matter for the purposes of interpreting, implementing and enforcing the terms and conditions of this Agreement and for the purpose of resolving disputes.

35. Nothing in this Agreement limits DEQ's right to take enforcement action for violations discovered or occurring after the effective date of this Agreement.

36. Nothing in this Agreement excuses PSO from its obligation to comply with all applicable federal, state and local statutes, rules and ordinances. PSO and DEQ agree that the provisions of this Agreement are considered severable, and if a court of competent jurisdiction finds any provisions to be unenforceable because they are inconsistent with state or federal law, the remaining provisions will remain in full effect.

37. To ensure continuous and uninterrupted responsibility for the activities required by this Agreement, PSO agrees to provide a copy of the Agreement to any purchaser of an affected unit prior to sale. PSO agrees to notify any such purchaser that the obligations under this Agreement are binding on the purchaser and shall notify DEQ of the sale within ten (10) days thereof and provide DEQ with the name of the purchaser.

38. The provisions of this Agreement apply to and bind PSO and DEQ and their officers, directors, employees, agents, successors and assigns. No change in the ownership or corporate status of PSO will affect PSO's responsibilities under this Agreement.

39. This Agreement is for the purpose of settlement. Neither the fact that PSO and DEQ have agreed to this Agreement, nor the Findings of Fact and Conclusions of Law in it, shall be used for any purpose in any proceeding except the enforcement by PSO and DEQ of this Agreement and, if applicable, a future determination by DEQ of eligibility for licensing or permitting. As to others who are not parties to this Agreement, nothing contained in this Agreement is an admission by PSO of the Findings of Fact or Conclusions of Law, and this Agreement is not an admission by PSO of liability for conditions at or near the facility and is not a waiver of any right, cause of action or defense PSO otherwise has.

40. PSO and DEQ agree that the venue of any action in district court for the purposes of interpreting, implementing and enforcing this Agreement will be Oklahoma County, Oklahoma.

41. The requirements of this Agreement will be considered satisfied and this Agreement terminated when PSO receives written notice from DEQ that PSO has demonstrated that all the terms of the Agreement have been completed to the satisfaction of DEQ.

42. PSO and DEQ may amend this Agreement by mutual consent. Such amendments must be in writing and the effective date of the amendments will be the date on which they are filed by DEQ.

43. The individuals signing this Agreement certify that they are authorized to sign it and to legally bind the parties they represent.

44. This Agreement becomes effective on the date of the later of the two signatures below.

Date: 1/19/10

FOR THE PUBLIC SERVICE COMPANY OF OKLAHOMA:

Stuart Solomon

STUART SOLOMON
PRESIDENT and CHIEF OPERATING OFFICER

Date: 2-17-10

FOR THE OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY:

Steven A. Thompson

STEVEN A. THOMPSON
EXECUTIVE DIRECTOR

Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis **January 19, 2010**

COMPANY:	**AEP- Public Service Company of Oklahoma**
FACILITY:	**Comanche Power Station**
FACILITY LOCATION:	**Comanche County, Oklahoma**
TYPE OF OPERATION:	**(2) 94 MW Gas Turbine Electric Generating Units**
REVIEWER:	**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).

Comanche Units 1 and 2 are fossil-fuel fired steam electric plants with heat inputs greater than 250-mmBtu/hr. The 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, the units have the potential to emit more than 250 tons per year of NO_X, a visibility impairing pollutant. Therefore, Comanche Units 1 and 2 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 AEP-PSO determined that the maximum predicted visibility impacts from Comanche Units 1 and 2 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, Comanche Units 1 and 2 were determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Comanche Units 1 and 2 were developed based on a combination of CEM data and operating records. 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, baseline 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 maximum hourly mass emission rates for each turbine by the turbine's full heat input at that rate. In addition, the duct burners have not operated for several years, and not over the baseline period. Emissions for the duct burners are not included in the analysis.

Table 1: Comanche Power Station- Operating Parameters for BART Evaluation

Parameter	Comanche Unit 1		Comanche Unit 2	
Plant Configuration	Combustion Turbine with Integrated Heat Recovery Steam Genertor		Combustion Turbine with Integrated Heat Recovery Steam Genertor	
Gross Output (nominal)	94 MW		94 MW	
Maximum Input to Turbine	1,250 mmBtu/hr		1,250 mmBtu/hr	
Primary Fuel	Natural gas		Natural gas	
Existing NO_X Controls	None		None	
Existing PM_{10} Controls	NA		NA	
Existing SO_2 Controls	NA		NA	
Baseline Emissions Pollutant	**Baseline Actual Emissions**		**Baseline Actual Emissions**	
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	**870.0**	**0.696**	**766.3**	**0.613**
SO_2	**0.75**	--	**0.75**	--
PM_{10}	**8.25**	--	**8.25**	--

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.

Because the units fire natural gas, emissions of sulfur dioxide (SO_2) and particulate matter (PM) are minimal. There are no SO_2 or PM post-combustion control technologies with a practical application to natural gas-fired turbines. BART is good combustion practices. A full BART analysis was conducted for NO_X.

Table 2: Proposed BART Controls and Limits

Unit	NO_X BART Emission Limit	BART Technology
Comanche Unit 1	0.15 lb/mmBtu (30-day average)	Dry Low NO_X Burners (DLNB)
Comanche Unit 2	0.15 lb/mmBtu (30-day average)	Dry Low NO_X Burners (DLNB)

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 Comanche Units 1 and 2 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Dry Low NO_X Burners (DLNB)
Post Combustion Controls
Selective Catalytic Reduction (SCR)

In support of the Regional Haze Rule, EPA also prepared a cost-effectiveness analysis for retrofit control technologies on oil- and gas-fired units. EPA's analysis concluded that, although a number of oil- and gas-fired units could make significant cost-effective reductions in NO_X emissions using currently available combustion control technologies, for a number of units the use of combustion controls did not appear to be cost effective. As a result, EPA determined that it would be inappropriate to establish a general presumption regarding likely BART limits for oil- and natural gas fired units.

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)

Combustion Controls:

Dry Low NO_X burners (DLNB)

Low NO_X burners (DLNB) limit NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperature resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperatures to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOX formation.

When utilized in new turbine designs, reductions of up to 60 percent may result. A similar level of effectiveness is expected with retrofit installations. This technology is considered a technically feasible option.

Post Combustion Controls:

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into turbine 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. The units at the Comanche Station employ combustion turbines with integrated Heat Recovery Steam Generators (HRSG) that are very unique in their designs. AEP-PSO contends that it is technically infeasible to retrofit post combustion SCR NO_X control without rebuilding the generating units. Therefore SCR is not evaluated further.

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Comanche Station

Control Technology	Comanche Unit 1 Approximate NO_X Emission Rate (lb/mmBtu)	Comanche Unit 2 Approximate NO_X Emission Rate (lb/mmBtu)
DLNB	0.15	0.15
Baseline	0.696	0.613

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

AEP evaluated the economic, environmental, and energy impacts associated with the proposed control option. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Capital costs associated with implementing the evaluated control system was provided to AEP-PSO by an after-market vendor. As LNB are not expected to incur any additional significant direct operating costs, total direct operating costs were assumed to be $0. Indirect operating costs are consistent with control manual guidance.

The capital recovery factor used to estimate the annual cost of control was based on an 8% interest rate and a control life of 20 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 53%.

Table 5: Economic Cost for Units 1 and 2

Cost	Control Option: DLNB
Control Equipment Capital Cost ($)	$34,660,000
Capital Recover Factor ($/Yr)	$3,530,198
Annual O&M Costs ($/Yr)	$1,386,400
Annual Cost of Control ($)	$4,916,598

Table 6: Environmental Costs for Units 1 and 2

	Unit	Baseline	DLNB
NO_X Emission Rate (lb/mmBtu)	Unit 1	0.48	0.15
	Unit 2	0.46	0.15
Annual NO_X Emission (TPY)[1]	Unit 1	1,393	435
	Unit 2	1,385	452
Annual NO_X Reduction (TPY)	Unit 1	--	958
	Unit 2	--	933
Annual Cost of Control	Units 1 & 2		$4,916,598
Cost per Ton of Reduction	--		$2,600

(1) Emissions for the BART analysis are based on maximum heat inputs of 1,250 mmBtu/hr. Annual emissions were calculated assuming a 53% capacity factor for unit 1 and a 55% capacity factor for unit 2.

B. 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 Comanche Power 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 Comanche Power 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 Comanche Generating Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Comanche 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.

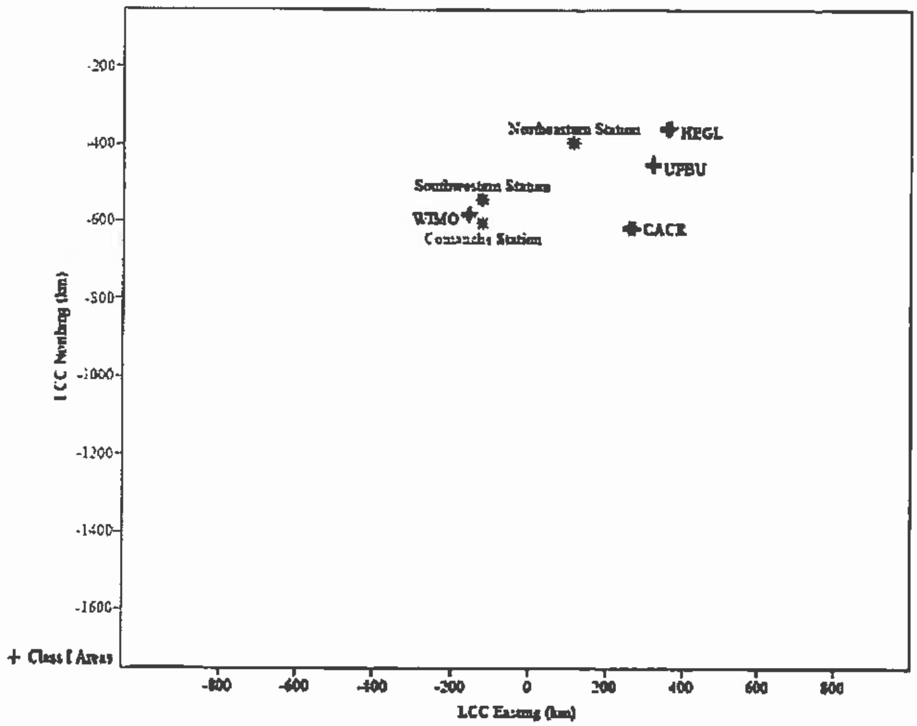

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING:

Because of the results of the applicants screening modeling for the Comanche Generating Station, AEP-PSO 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, August 2008)*

CALPUFF System

Predicted visibility impacts from the Comanche 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 most modeled areas are located more than 50 km from the sources in question and the Wichita Mountains are just under the threshold at 40 km, 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 7: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.51	030709

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 8: 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, 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

Variable	Description	Value
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.

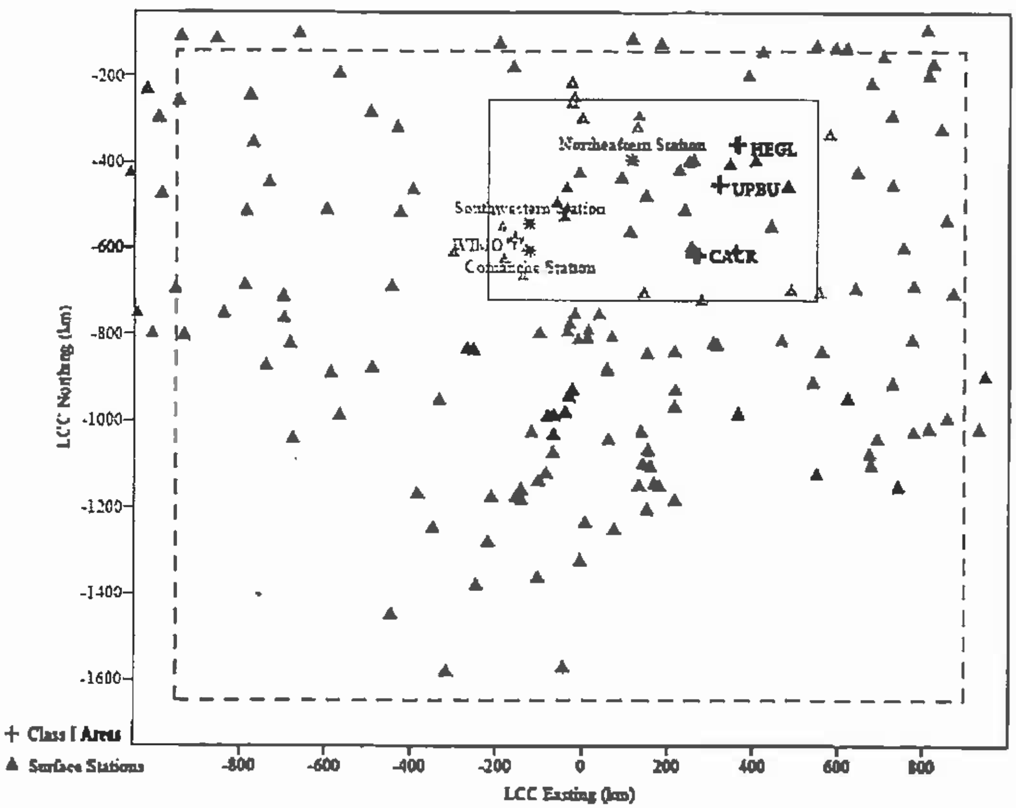

Figure 2: Plot of surface station locations

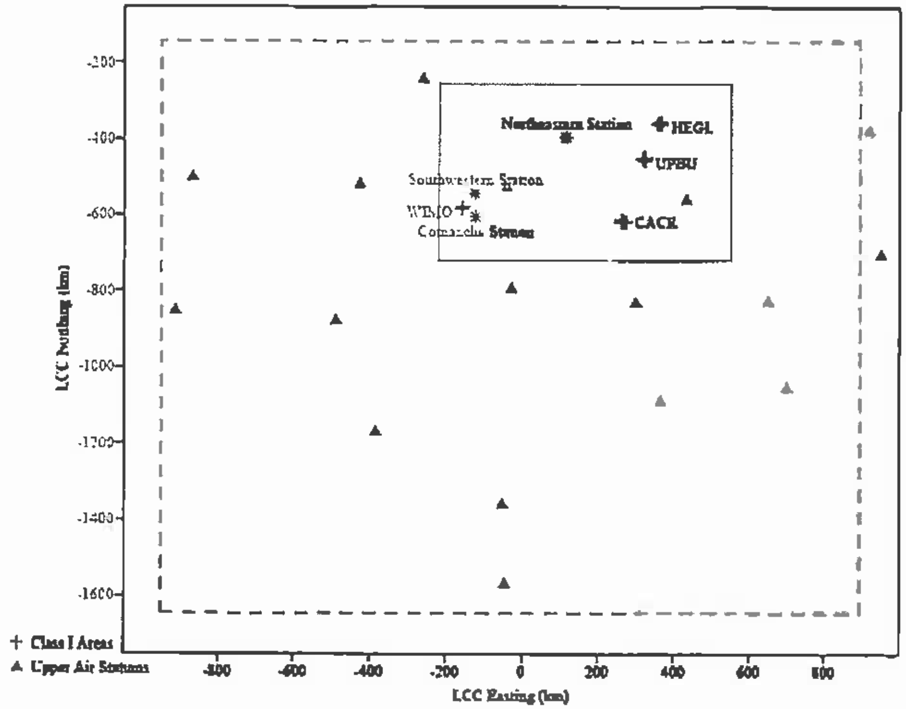

Figure 3: Plot of upper air station locations

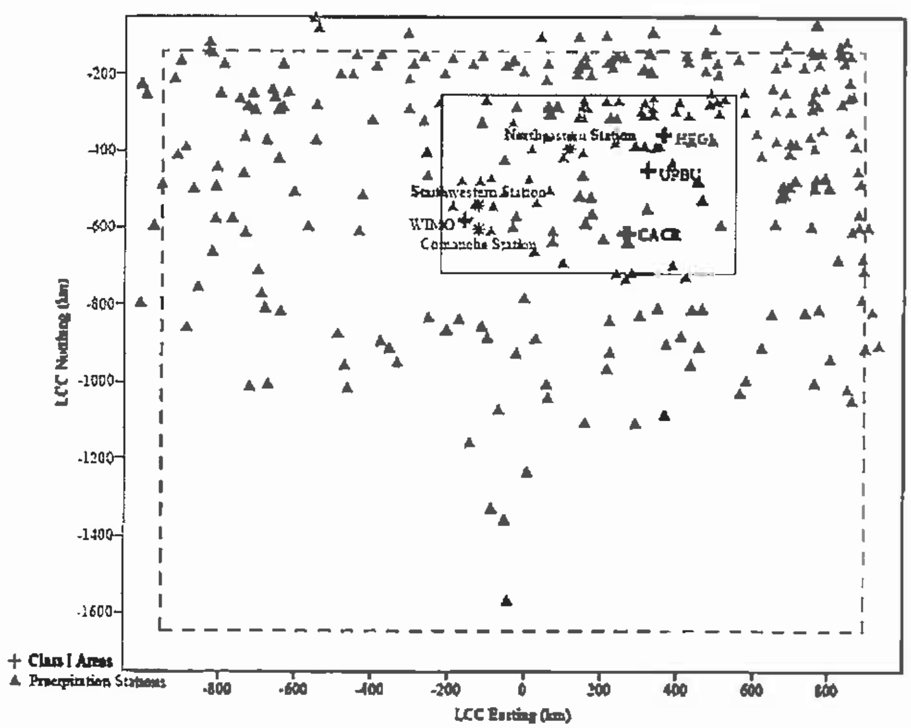

Figure 4. Plot of precipitation observation stations

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 for the baseline runs were established based on CEM data and the highest 24-hour emissions averages for years 2001 to 2005. All particulate emissions (PM) were based on emission rates of 0.0066 lb/mmBtu with 25% filterable (coarse PM) and 75% condensable treated as (fine PM) within CALPUFF and CALPOST.

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

Table 9: Baseline Source Parameters

Parameter	Baseline	
	Unit 1	Unit 2
Heat Input (mmBtu/hr)	1,250	1,250
Base Elevation (m)	338	338
Stack Height (m)	16	16
Stack Diameter (m)	3.11	3.11
Stack Temperature (K)	453	455
Exit Velocity (m/s)	44.82	44.82
SO2 Emissions (TPY)	0.75	0.75
NOX Emissions[1] (lb/mmBtu)	0.696	0.613
NOX Emissions TPY	870	766.3
PM_{10} Emissions Coarse (TPY)	2.06	2.06
PM_{10} Emissions Fine (TPY)	6.19	6.19

[1]Baseline NOx emissions were based on the maximum 24-hr average emission rate (lb/hr) reported by each unit during the baseline period 2003-2005. Baseline emissions data were provided by AEP-PSO. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum 24-hr lb/hr emission rate by the heat input to the turbine at that rate.

[2]PM emissions are based on AP-42 emission factors for stationary gas turbines with filterable/condensable speciation based on NPS guidance.

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 11: 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 12: CALPUFF Visibility Modeling Results for Comanche Units 1 and 2

Class I Area	2001	2002	2003	3-Year Average
	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	1.83	1.619	1.66	1.703
Caney Creek	0.103	0.097	0.08	0.093
Upper Buffalo	0.092	0.066	0.062	0.073
Hercules Glade	0.076	0.068	0.044	0.063
Scenario- Combustion Control- DLNB				
Wichita Mountains	0.47	0.395	0.406	0.424
Caney Creek	0.024	0.022	0.018	0.021
Upper Buffalo	0.021	0.015	0.014	0.017
Hercules Glade	0.017	0.015	0.010	0.014

C. 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 Comanche Generating Station.

New DLNB is determined to be BART for NO_X control for Units 1 and 2 based, in part, on the following conclusions:

1. Installation of new DLNB was cost effective, with a capital cost of $34,660,000 for units 1 and 2 and an average cost effectiveness of $2,600 per ton of NO_X removed for each unit over a twenty year operational life.

2. Combustion control using the LNB 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 1 and 2 are justified.

4. Annual NO_X emission reductions from new LNB on Units 1, and 2 are a total of 1,891 tons.

The Division considers the installation and operation of the BART determined NO_X controls, new DLNB, to meet the statutory requirements of BART.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)
Comanche Power Station is a major source under OAC 252:100-8 Permits for Part 70 Sources. AEP-PSO 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 Comanche Station.

With installation of the BART controls, the duct burners will no longer be authorized to operate.

VI. OPERATING PERMIT

The Comanche 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 turbines in EUG 1 and 2 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
1G1	1G1	Westinghouse /W-501B	1250	1971
1G2	1G2	Westinghouse /W-501B	1250	1971

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 turbines. 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 Dry Low-NO_X Burners, as determined in the submitted BART analysis, to reduce emissions of NO_X to below the emission limits below:

e. The permittee shall maintain the combustion controls (Low-NO_X burners) 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	Averaging Period
1G1	1G1	0.15 lb/MMBTU	30-day rolling
1G2	1G2	0.15 lb/MMBTU	30-day rolling

g. Within 60 days of achieving maximum power output from each turbine, after modification of the turbines, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing 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)]

1. 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.
2. The permittee shall also provide notice of the actual test date to AQD.

Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis **January 19, 2010**

COMPANY:	**AEP- Public Service Company of Oklahoma**
FACILITY:	**Southwestern Power Station**
FACILITY LOCATION:	**Caddo County, Oklahoma**
TYPE OF OPERATION:	**(1) 332 MW Steam Electric Generating Unit**
REVIEWER:	**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).

Southwestern Unit 3 is a fossil-fuel fired boiler with heat inputs greater than 250-mmBtu/hr. The unit was in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Based on a review of existing emissions data, the unit has the potential to emit more than 250 tons per year of NO_X, a visibility impairing pollutant. Therefore, Southwestern Unit 3 meets 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 AEP-PSO determined that the maximum predicted visibility impacts from Southwestern Unit 3 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, Southwestern Unit 3 was determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Southwestern Unit 3 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, baseline 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 maximum hourly mass emission rates for the boiler by the boiler's heat input at that emission rate.

Table 1: Southwestern Power Station- Plant Operating Parameters for BART Evaluation

Parameter	Southwestern Unit 3	
Plant Configuration	Natural Gas-Fired Boiler	
Gross Output (nominal)	332 MW	
Maximum Input to Boiler	3,290 mmBtu/hr	
Primary Fuel	Natural gas	
Existing NO_X Controls	None	
Existing PM_{10} Controls	NA	
Existing SO_2 Controls	NA	
Baseline Emissions Pollutant	**Baseline Actual Emissions**	
	lb/hr	**lb/mmBtu**
NO_X	**3,705**	**1.126**
PM_{10}	**24.5**	**0.007**
SO_2	**1.97**	**0.0006**

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.

Because the unit fires natural gas, emissions of sulfur dioxide (SO_2) and particulate matter (PM) are minimal. There are no SO_2 or PM post-combustion control technologies with a practical application to natural gas-fired boilers. BART is good combustion practices. A full BART analysis was conducted for NO_X.

Table 2: Proposed BART Controls and Limits

Unit	NO_X BART Emission Limit	BART Technology
Southwestern Unit 3	0.45 lb/mmBtu (30-day average)	LNB/OFA

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 Southwestern Unit 3 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Burners Out of Service (BOOS)
Low NO_X Burners and Overfire Air (LNB/OFA)
Induced Flue Gas Recirculation (FGR)
Post Combustion Controls
Selective Catalytic Reduction (SCR)

In support of the Regional Haze Rule, EPA also prepared a cost-effectiveness analysis for retrofit control technologies on oil- and gas-fired units. EPA's analysis concluded that, although a number of oil- and gas-fired units could make significant cost-effective reductions in NO_X emissions using currently available combustion control technologies, for a number of units the use of combustion controls did not appear to be cost effective. As a result, EPA determined that it would be inappropriate to establish a general presumption regarding likely BART limits for oil- and natural gas fired units.

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)

Combustion Controls:

Burners Out of Service (BOOS)

This option involves shutting off selected burners, resulting in reduced fuel usage and therefore lower emissions. This option would essentially reduce the maximum firing rate of the boiler, and places a load limit on the unit. AEP-PSO estimates that NO_X emissions can be reduced 20-25%. Implementation of this option will reduce the maximum firing rate of the unit, thereby creating an artificial load limit. Although this does not preclude this option from being physically implemented, the resulting load limits would effectively result in the shutdown of the units. As a result, this option is considered technically infeasible.

Induced Flue Gas Recirculation (IFGR)
FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces thermal NO_X formation. When operated without additional controls, the average NO_X control efficiency range for FGR is 30 percent to 40 percent. This control option would also place load limits on the boiler and also call for plant component upgrades. As with the Burners Out Of Service, IFGR is considered technically infeasible as a standalone NO_X control for Southwestern Power Station Unit 3.

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 natural gas-fired boilers. Boilers of the size and age of the Southwestern Unit would be expected to achieve an average emission reduction in the range of 30% to 60% from baseline depending on the baseline emission rate and boiler operating conditions. Southwestern Unit 3 does not operate as base load units. The unit has historically operated as a "peaking unit" responding to increased demand for electricity. While technically feasible, LNB/OFA may not be as effective under all boiler operating conditions, especially during load changes and at low and high operating loads.

Post Combustion Controls:
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 N_2 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 gas-fired boilers. Based on emissions data available from the EPA Electronic Reporting website, large gas-fired boilers (with heat inputs above approximately 1,000 mmBtu/hr) have achieved actual long-term average NO_X emission rates in the range of approximately 0.02 to 0.05 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 gas-fired units, and taking into consideration long-term operation of an SCR control system (including catalyst plugging and deactivation) and the fact that the Southwestern boiler typically operates as a peaking unit, it is anticipated that SCR could achieve a controlled NO_X emission rate of 0.05 lb/mmBtu (30-day rolling average) on Southwestern Unit 3.

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Southwestern Station

Control Technology	Southwestern Unit 3
	Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.05
LNB/OFA	0.45
Baseline[1]	1.126

[1]Baseline emissions for modeling are based on the maximum 24-hour emission rate over the baseline period. Baseline emissions for cost effectiveness calculations were based on the annual average emission rate of 0.57 lb/mmBtu.

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

AEP-PSO evaluated the economic, environmental, and energy impacts associated with the 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 costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit Southwestern Unit 3 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) and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with operation of the new control technology. The capital recovery factor used to estimate the annual cost of control was based on a 8% interest rate and a control life of 20 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 26%.

Table 5: Economic Cost

Cost	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR
Control Equipment Capital Cost ($)	$3,000,000	$68,968,400
Capital Recover Factor ($/Yr)	$305,557	$7,024,584
Annual O&M Costs ($/Yr)	$120,000	$3,682,650
Annual Cost of Control ($)	$425,557	$10,707,234

Table 6: Environmental Costs per Boiler

	Baseline	LNB/OFA	LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu)	0.57	0.45	0.05
Annual NO_X Emission (TPY)	2,136	1,686	187
Annual NO_X Reduction (TPY)	--	450	1,949
Annual Cost of Control	--	$425,557	$10,707,234
Cost per Ton of Reduction	--	$946	$5,494
Incremental Cost per ton of Reduction	--	--	$6,859

B. 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 Southwestern Power 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 Southwestern Power 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 Southwestern Power Station, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Southwestern Power 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.

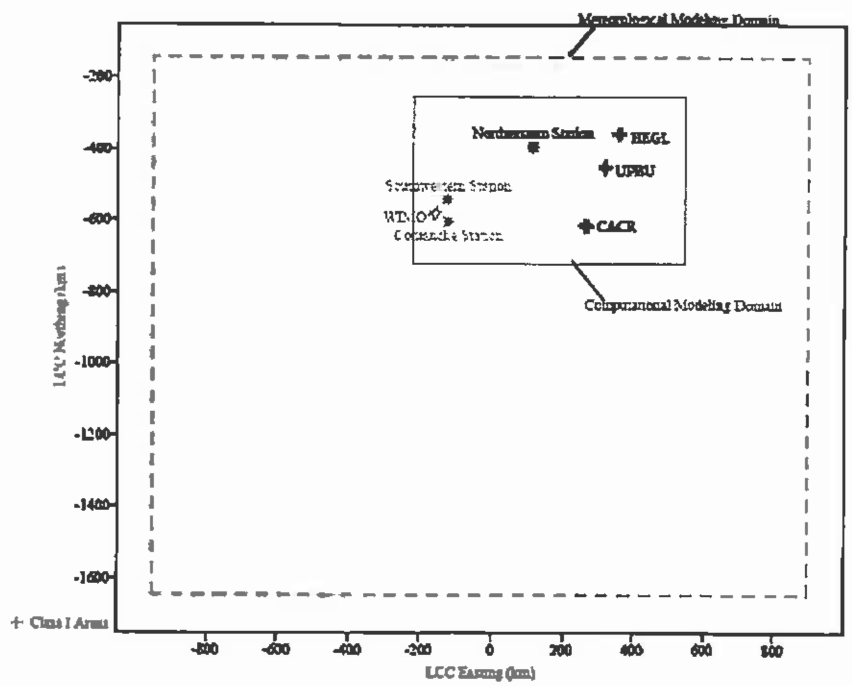

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING:

Because of the results of the applicants screening modeling for the Southwestern Power Station, AEP-PSO 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, August 2008)*

CALPUFF System

Predicted visibility impacts from the Southwestern Power 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 most modeled areas are located more than 50 km from the sources in question and the Wichita Mountains are within 44 km, 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 7: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	5.51	030709

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 8: 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, 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.

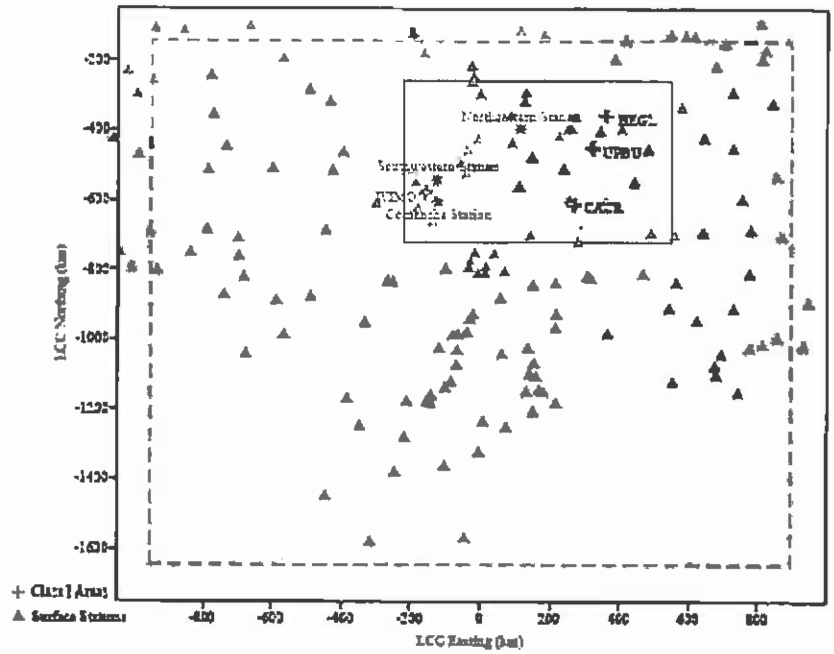

Figure 2: Plot of surface station locations

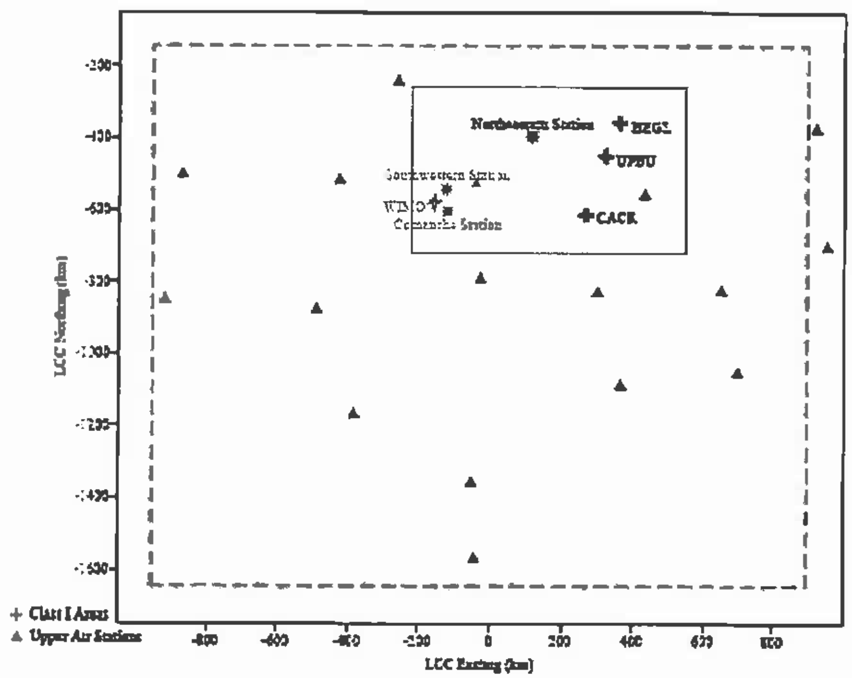

Figure 3: Plot of upper air station locations

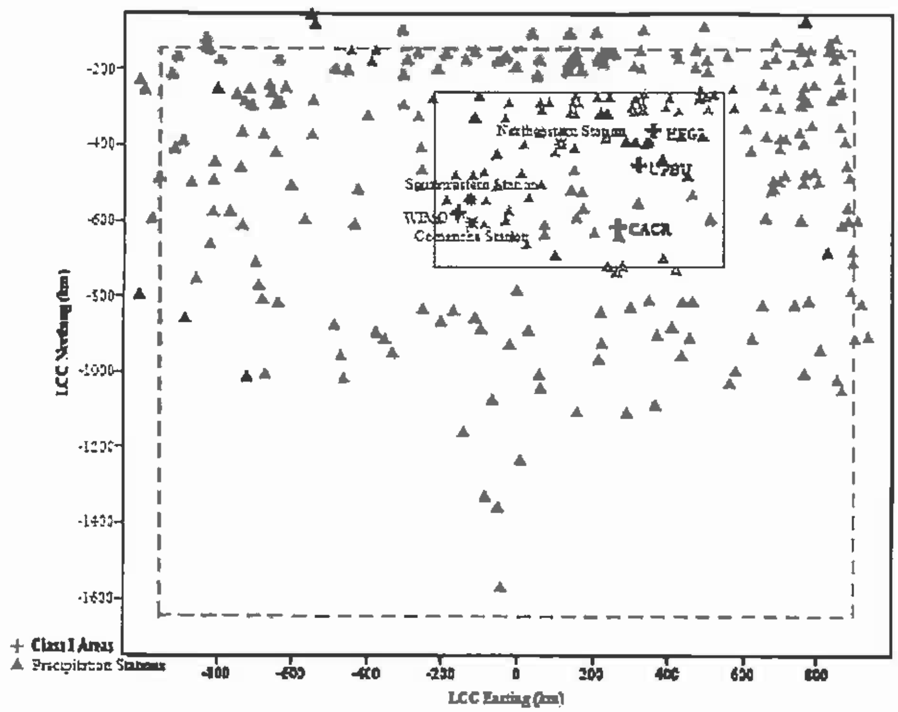

Figure 4. Plot of precipitation observation stations

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 for the baseline runs were established based on CEM data and maximum 24-hour emissions averages for years 2001 to 2005.

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

Table 9: Baseline Source Parameters

Parameter	Southwestern Unit 3 Natural Gas-Fired
Heat Input (mmBtu/hr)	3,290
Base Elevation (m)	371
Stack Height (m)	43
Stack Diameter (m)	4.27
Stack Temperature (K)	408
Exit Velocity (m/s)	16.26
SO2 Emissions (lb/mmBtu)	0.0006
SO2 Emissions (TPY)	8.63
NOX Emissions[1] (lb/mmBtu)	1.26
NOX Emissions TPY	16227.9
PM_{10} Fine Emissions[2] (lb/mmBtu)	0.00175
PM_{10} Fine Emissions (TPY)	6.13
PM_{10} Coarse Emissions (lb/mmBtu)	0.00525
PM_{10} Coarse Emissions (TPY)	18.39

[1]**Baseline NOx emissions were based on the maximum 24-hr average emission rate (lb/hr) reported by the unit during the baseline period 2003-2005. Baseline emissions data were provided by AEP-PSO. 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 at that emission rate.**

[2]**PM emissions are based on AP-42 emission factors for natural gas combustion and NPS speciation factors for (filterable and condensable).**

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 11: 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 12: CALPUFF Visibility Modeling Results for Southwestern Unit 3

Class I Area	2001 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	3.86	2.85	3.74	3.48
Scenario 2- Combustion Control- LNB/OFA				
Wichita Mountains	1.73	1.24	1.70	1.56

Modeling for SCR controls resulted in an approximately 88% reduction in visibility impairment from scenario two.

C. 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 unit at the Southwestern Power Station.

New LNB with OFA is determined to be BART for NOX control for Unit 3 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective, with a capital cost of $3,000,000 and an average cost effectiveness of $947 per ton of NO_X removed over a twenty 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 NO_X control levels on 30-day rolling averages of 0.45 lb/mmBtu for Unit 3 are justified.

4. Annual actual NO_X emission reductions from new LNB with OFA on Unit 3 are 450 tons.

LNB with OFA and SCR was not determined to be BART for NO_X control for Unit 3 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 Unit 3 are $65,968,400. Based on projected actual emissions, SCR could reduce overall NO_X emissions from Southwestern Unit 3 by approximately 1,441 tpy (compared to combustion controls); however, the incremental cost associated with this reduction is approximately $10,281,677 per year, or $6,859/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. SCR control may not be as effective on boilers that operate as peaking units, as NO_X reduction in an SCR is a function of flue gas temperature.

The Division considers the installation and operation of the BART determined NO_X controls, new LNB with OFA, to meet the statutory requirements of BART.

V. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)
Southwestern Power Station is a major source under OAC 252:100-8 Permits for Part 70 Sources. AEP-PSO 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 Southwestern Station.

VI. OPERATING PERMIT

The Southwestern Power 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. Unit 3 in EUG 1 is 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	3	Babcock/Wilcox, **RB-426**	3,290	May 1967

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 NOX to below the emission limits below:
   i. Low-NOX Burners,
   ii. Overfire Air, and

e. The permittee shall maintain the combustion controls (Low-NOX burners, overfire air) 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#	NOX Emission Limit	Averaging Period
3	03	0.45 lb/MMBTU	30-day rolling

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

h. After installation of the BART, the affected facilities shall only be fired with natural gas.

i. Within 60 days of achieving maximum power output from the boiler, after modification of the boiler, 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 NOX, 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.

iii. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.

EXHIBIT C

Oklahoma Department of Environmental Quality
Air Quality Division

BART Application Analysis | **January 19, 2010**

COMPANY:	**AEP-Public Service Company of Oklahoma**
FACILITY:	**Northeastern Power Plant**
FACILITY LOCATION:	**Rogers County, Oklahoma**
TYPE OF OPERATION:	**(1) 495 MW Natural Gas-Fired Steam Electric Generating Unit** **(2) 490 MW Coal-Fired 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).

Northeast Units 2, 3 and 4 are fossil-fuel fired boilers with heat inputs greater than 250-mmBtu/hr. All three 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, the units have the potential to emit more than 250 tons per year of NO_X, SO_2, and PM_{10}, visibility impairing pollutants. Therefore, Northeast Units 2, 3 and 4 meet the definition of BART-eligible sources.

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 AEP-PSO determined that the maximum predicted visibility impacts from Northeast Units 2, 3 and 4 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains, Caney Creek, Upper Buffalo, and Hercules Glade Class I Areas. Therefore, Northeast Units 2, 3 and 4 were determined to be BART applicable sources, subject to the BART determination requirements.

III. DESCRIPTION OF BART SOURCES

Baseline emissions from Northeastern Units 2, 3 and 4 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: Northeastern Power Plant- Plant Operating Parameters for BART Evaluation

Parameter	Northeastern Unit 2		Northeastern Unit 3		Northeastern Unit 4	
Plant Configuration	Natural Gas-Fired Boiler		Coal-Fired Boiler		Coal-Fired Boiler	
Firing Configuration			Tangentially-fired		Tangentially-fired	
Gross Output (nominal)	495 MW		490 MW		490 MW	
Maximum Input to Boiler	4,754 mmBtu/hr		4,775 mmBtu/hr		4,775 mmBtu/hr	
Maximum 24-hour Average Input	4,767 mmBtu/hr		5,812 mmBtu/hr		5,594 mmBtu/hr	
Primary Fuel	Natural Gas		Sub-bituminous coal		Sub-bituminous coal	
Existing NO_X Controls	1st Generation LNB/OFA		1st Generation LNB/OFA		1st Generation LNB/OFA	
Existing PM_{10} Controls	NA		Electrostatic precipitator		Electrostatic precipitator	
Existing SO_2 Controls	NA		Low-sulfur coal		Low-sulfur coal	
Maximum 24-hour Emissions (CALPUFF Model)						
	Unit 2		**Unit 3**		**Unit 4**	
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**

NO_X	3,385	0.71	3,116	0.536	2,747	0.491
SO_2	2.9	0.0006	6,106	1.05	5,930	1.06
PM_{10}	35.4	0.007	220	0.038	330	0.059
Baseline Emissions (2004- 2006)						
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	1462	0.449	1838	0.397	1827	0.404
SO_2	1.66	0.0006	4235	0.914	4102	0.907

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 Northeast Units 3 and 4 (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**
Northeastern Unit 2	0.28 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Northeastern Unit 3	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Northeastern Unit 4	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Unit	**SO_2 BART Emission Limit**	**BART Technology**
Northeastern Unit 3	0.65 lb/mmBtu (30-day average)	Low Sulfur Coal
Northeastern Unit 4	0.65 lb/mmBtu (30-day average)	Low Sulfur Coal
Unit	**PM_{10} BART Emission Limit**	**BART Technology**
Northeastern Unit 3	0.1 lb/mmBtu (3-hour average)[1]	Existing ESP

Northeastern Unit 4	0.1 lb/mmBtu (3-hour average)[1]	Existing ESP

[1]Current emissions limits for ESPs are based on minimum NSPS requirements for front half catch. As part of the permitting process, PSO will be required to propose emission limits for front and back half reflective of the control technology and consistent with performance test results.

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 Northeast Units 2, 3 and 4 are listed in Table 3.

Table 3: List of Potential Control Options

Control Technology
Combustion Controls
Burners Out of Service (NE 2 only)
Flue Gas Recirculation (FGR)
Low NO_X Burners and Overfire Air (LNB/OFA)
Post Combustion Controls
Selective Noncatalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Reburning /Methane de-NO_X (MdN)

ELIMINATE TECHICALLY INFEASIBLE OPTIONS (NO_X)

Combustion Controls:

Burners Out of Service

This option involves shutting off selected burners, resulting in reduced fuel usage and therefore lower emissions. This option would essentially reduce the maximum firing rate of the boiler, and place a load limit on the unit. The resulting load limits would effectively result in the shutdown of the unit and as a result, this option is considered technically infeasible.

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 O_2 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 Northeast Units 3 and 4, and will not be considered further in the BART determination.

For Unit 2, Induced Flue Gas Recirculation (IFGR) would also place load limits on the boiler and call for plant equipment upgrades. As with the Burners Out of Service option, IFGR is considered technically infeasible.

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. Northeast Units 3 and 4 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.

For the natural gas-fired Unit 2, OFA as a single NO_X control technique may reduce NO_X emissions by 25-55 percent. When combined with LNB, reductions of up to 60% may result. This technology is a feasible option for all three units.

Reburning/Methane De-NO_X

In reburning, also known as "off-stoichiometric combustion" or "fuel staging," a fraction (5 to 25 percent) of the total fuel heat input is diverted to a second combustion zone downstream of the primary zone. The fuel in the fuel-rich secondary zone acts as a reducing agent, reducing NO, which is formed in the primary zone, to N_2. Generally, it is more economical for a facility to use the same fuel for reburning as it does for primary combustion, although there are exceptions. In order to use coal as a reburning fuel, it must be finely ground, which requires additional pulverizing equipment.

Methane de- NO_X (MdN) utilizes the injection of natural gas together with recirculated flue gases (for enhanced mixing) to create an oxygen-rich zone above the combustion grate. OFA is then injected at a higher furnace elevation to burn out the combustibles. This process is claimed to yield between 50 and 70 percent NO_X reduction and to be suitable for all solid fuel-fired stoker boilers. However, as of 2002, MdN had only been demonstrated for a short duration in one pulp mill wood-fired stoker boiler that also burned small amounts of waste treatment plant residuals, with NO_X reductions of 40 to 50 percent reported.

MdN is not considered feasible for the coal-fired units because (1) it is not fully demonstrated and (2) it incorporates FGR, which is technically infeasible for all three units.

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 Northeastern 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 Northeastern 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 Northeastern, has not been demonstrated in practice. Assuming that SNCR could be installed on the Northeastern 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.

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 N_2 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 0.054 lb/mmBtu on Northeast Unit 3 and 0.049 lb/mmBtu on Unit 4. The addition of SCR controls to Unit 2 could result in a controlled NO_X emission rate of 0.05 lb/mmBtu.

EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (NO_X)

Table 4: Technically Feasible NO_X Control Technologies- Northeastern Power Plant

Control Technology	Northeastern Unit 2 Approximate NO_X Emission Rate (lb/mmBtu)	Northeastern Unit 3 Approximate NO_X Emission Rate (lb/mmBtu)	Northeastern Unit 4 Approximate NO_X Emission Rate (lb/mmBtu)
LNB/OFA + SCR	0.05	0.054	0.049
LNB/OFA	0.28	0.15	0.15
SCNR	--	0.402	0.368
Baseline	0.449	0.397	0.404

EVALUATE IMPACTS AND DOCUMENT RESULTS (NO_X)

AEP-PSO evaluated the economic, environmental, and energy impacts associated with the proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Capital costs were developed by AEP-PSO and are based on equipment costs for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit Northeast Units 2, 3 and 4 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) 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 an 8% interest rate and a control life of 20 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 21% for Unit 2 and a capacity factor of 85% for SO_2 control effectiveness calculations for Units 3 and 4. No capacity factors were used for NO_X control effectiveness calculations.

AEP-PSO 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 for Units 3 and 4 (Coal-Fired Boilers)

Cost	Option 1: SNCR[2]	Option 2: LNB/OFA	Option 3: LNB/OFA +SCR[1]
Total Capital Investment ($)	$11,500,000	$17,000,000	$290,000,000
Annualized Capital Cost ($/Yr)	$1,171,300	$1,731,488	$29,537,141
Annual O&M Costs ($/Yr)	$13,602,120	$680,000	$18,248,660
Annual Cost of Control ($)	$14,773,420	$2,411,488	$47,785,801

[1]While not stated explicitly, costs for SCR are assumed to encompass LNB/OFA as well.
[2]Costs associated with SNCR are greater than LNB/OFA with less potential reduction in emissions, no further review will be required.

Table 6: Environmental Costs for Units 3 and 4 (Coal-Fired Boiler)

	Baseline	LNB/OFA	LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu) Unit3	0.397	0.15	0.054
NO_X Emission Rate (lb/mmBtu) Unit4	0.404	0.15	0.049
Annual NO_X Emission (TPY)[1]	13,971	6,274	2,154
Annual NO_X Reduction (TPY)	--	7,697	11,817
Annual Cost of Control	--	$2,411,488	$47,785,801
Cost per Ton of Reduction	--	$313	$4,044
Incremental Cost per ton of Reduction[2]	--		$11,013

(1) Emissions for the BART analysis are based on annual average emissions from 2004-2006 for Units 3 & 4.
(2) Incremental cost effectiveness of the SCR system is compared to costs/emissions associated with LNB/OFA controls.

Table 7: Economic Cost for Unit 2 (Natural Gas-Fired Boilers)

Cost	Option 1: LNB/OFA	Option 2: LNB/OFA +SCR[1]
Total Capital Investment ($)	$3,450,000	$94,743,000
Annualized Capital Cost ($/Yr)	$351,390	$9,649,784
Annual O&M Costs ($/Yr)	$138,000	$3,789,720
Annual Cost of Control ($)	$489,390	$14,366,357

[1]While not stated explicitly, costs for SCR are not assumed to encompass LNB/OFA based on the incremental cost analysis completed by the applicant.

Table 8: Environmental Costs for Unit 2 (Natural Gas-Fired Boiler)

	Baseline	Option 2: LNB/OFA	Option 3: LNB/OFA +SCR
NO_X Emission Rate (lb/mmBtu) Unit2	0.449	0.285	0.05
Annual NO_X Emission (TPY)[1]	2,861	1,246	219
Annual NO_X Reduction (TPY)	--	1615	2642
Annual Cost of Control		$489,390	$14,366,357
Cost per Ton of Reduction		$303	$5,438
Incremental Cost per ton of Reduction[2]			$13,512

(1) Emissions for the BART analysis are based on annual average emission from 2005- 2006 (2004 emissions are not reflective of annual averages. Annual costs for LNB/OFA assumed a capacity factor of 0.21. The applicant used a capacity factor of 0.19 in the SCR evaluation; however, the analysis reported here reflects the 0.21 capacity factor documented in the original submittal.
(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 Northeast Units 3 and 4 are listed in Table 9.

Table 9: List of Potential Control Options

Control Technology
Pre-Combustion Control
Wet Flue Gas Desulfurization
Dry Flue Gas Desulfurization-Spray Dryer Absorber

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. Northeast Units 3 and 4 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; however, subbituminous coal with lower sulfur content is achievable and available. Fuel switching to a lower sulfur content coal is a viable option.

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.

Northeast Units 3 and 4 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 Northeast Units 3 and 4.

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 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 coal-fired boiler, using processed fuels in Northeast Units 3 and 4 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.

Wet Lime Scrubbing
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.

Wet Limestone Scrubbing
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. Northeast Units 3 and 4 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 Northeast Units 3 and 4 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 Northeast Units 3 and 4, 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 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 Northeast Units 3 and 4. 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 0.15 lb/mmBtu (30-day average) on an on-going long-term basis.

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 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 AEP-PSO would be required to conduct extensive design engineering to scale up the technology for boilers the size of Northeast Units 3 and 4, and that AEP-PSO 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 Northeast Units 3 and 4, and will not be evaluated further in this BART determination.

EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES (SO_2)

Table 10: Technically Feasible SO_2 Control Technologies- Northeastern Station

Control Technology	Northeastern Unit 3 Approximate SO_2 Emission Rate (lb/mmBtu)	Northeastern Unit 4 Approximate SO_2 Emission Rate (lb/mmBtu)
Wet FGD	0.063	0.063
Dry FGD- Spray Dryer Absorber	0.153	0.153
Lower Sulfur Coal	0.55	0.55
Baseline	0.9	0.9
Annual Average Baseline	0.91	0.91

EVALUATE IMPACTS AND DOCUMENT RESULTS (SO_2)

AEP-PSO 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. Cost estimates include the equipment, material, labor, and all other direct costs needed to retrofit Northeast Units 3 and 4 with the control technologies.

Direct O&M costs are those costs that tend to be proportional to the quantity of exhaust gas processed by the control system. These may include costs for catalysts, utilities (steam, electricity, and water), waste treatment and disposal, maintenance materials, replacement parts, and operating and maintenance labor. Of these direct O&M costs, costs for catalysts, utilities, waste treatment, and disposal are variable. Emission allowance costs associated with certain regulatory programs may also be represented as a variable O&M costs, but have not been included in this cost estimate. Indirect or "Fixed" annual costs are those whose values are totally independent of the exhaust flow rate and, in fact, would be incurred even if the control system were shut down. They include such categories as administrative charges, property taxes, and insurance, and include the capital recovery cost. The direct and indirect annual costs are offset by recovery credits, taken for materials or energy recovered by the control system, which may be sold, recycled to the process, or reused elsewhere at the site. The capital recovery factor used to estimate the annual cost of control was based on a 8% interest rate and a control life of 20 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 85%.

AEP-PSO submitted initial cost estimates in 2008 that relied upon a baseline emission rate representative of the average annual emission (0.9 lb/mmBtu) at an annual average firing rate of 4775 mmBtu/hr. The modeling demonstration relied on maximum 24-hr heat input numbers that were somewhat larger than the average. However the actual annual firing rate is much lower, and costs were reevaluated in order to be consistent with the methodology employed by EPA. 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.

The engineering estimates and possible vendor quotations AEP-PSO relied on to develop base $/kW Total Capital Investment assumptions were not provided to substantiate the capital costs for installation. In reviewing BART submittals to other states, AEP-PSO's estimated costs were found to be somewhat higher than those reported for similar projects. However, the evaluations in neighboring states are known to underestimate present day costs and the analysis submitted by AEP-PSO is in line with the more detailed and recent analyses submitted by OG&E.

Operation and maintenance cost estimates for AEP-PSO cost calculations rely on assumptions provided in the AEP-PSO submittal. While the assumptions for administrative costs were overstated, AEP-PSO failed to incorporate labor, maintenance, and increased water costs, which offset the overestimated numbers. Estimates are compared to 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 reproduces a Sargent and Lundy graphic, which lists a cost range in $/kW of 15 to 38 for O&M costs. AEP-PSO estimates are approximately $33/kW. AEP-PSO's estimates are again comparable to the DEQ approved more recent and detailed cost estimates for OG&E.

Table 11: Economic Cost for Unit 3 and 4 - Dry FGD- Spray Dryer Absorber

Cost	DFGD/SDA
Total Capital Investment ($)	$546,700,000
Total Capital Investment ($/kW)	$582
Capital Recovery Cost ($/Yr)	$55,682,603
Annual O&M Costs ($/Yr)	$31,070,200
Total Annual Cost ($)	$86,752,803

Table 12: Environmental Costs for Unit 3 and 4

	Baseline	Lower S Coal	DFGD/SDA
SO_2 Emission Rate (lb/mmBtu)	0.91	0.55	0.153
Annual SO_2 Emission (TPY)[1]	31,779	19,555	5,440
Annual SO_2 Reduction (TPY)	--	12,224	26,339
Total Annual Cost ($)			$86,752,803
Cost per Ton of Reduction			$3,294

Incremental Cost per Ton			$6,146

[1] Baseline annual emissions were averaged based on annual emissions from 2004- 2006. Projected annual emissions were calculated based on the controlled SO_2 emissions rate, full load heat input of 4,775 mmBtu/hr, and assuming an 85% capacity factor.

Table 13: Environmental Costs for Units 3 and 4- Wet FGD

Cost	AEP-PSO Cost Estimates Units 3 and 4
Total Capital Investment ($)	$703,680,000
Total Capital Investment ($/kW)	$749
Capital Recovery Cost ($/Yr)	$71,671,362
Annual O&M Costs ($/Yr)	$35,419,400
Total Annual Cost ($)	$107,090,762
Baseline SO_2 Emission Rate (lb/mmBtu)	0.9
Control SO_2 Emission Rate (lb/mmBtu)	0.063
Baseline Annual Emissions (TPY)[1]	31,779
Controlled Annual SO_2 Emission (TPY)[1]	2,240
Annual SO_2 Reduction (TPY)	29,539
Cost per Ton of Reduction ($/Ton)	$3,625
Incremental Annual Cost ($/Ton)	$6,356

[1] Baseline annual emissions were calculated based on annual average emissions from 2004-2006.. Projected annual emissions were calculated based on the controlled SO_2 emissions rate, full load heat input of 4,775 mmBtu/hr, and assuming an 85% 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). Northeast Units 3 and 4 are currently equipped with ESP control systems.

Table 14: Summary of Technically Feasible Main Boiler PM_{10} Control Technologies

Control Technology	PM_{10} Emissions (lb/mmBtu)	% Reduction (from base case)
Fabric Filter Baghouse and ESP	0.0085/0.0079	99.9
ESP - Existing	0.025/0.040	99.7

EVALUATE IMPACTS AND DOCUMENT RESULTS (PM_{10})

Costs for Fabric Filter Baghouses were provided separate from the cost estimates provided by AEP-PSO for Dry FGD. While DEQ capital cost estimates rely on primarily fully loaded Wet FGD installations, the greater expense attributed to wet versus dry systems can account for the Fabric Filter Baghouse equipment cost without a direct line item cost.

For fabric filter baghouse controls AEP-PSO estimated a total capital investment of $71,050,000 for Units 3 and 4. The capital recovery cost was estimated to be $6,671,463 per year over 20 years at 7% interest. The total annual cost was estimated to be $12,773592. Addition of the fabric filters was anticipated to result in an incremental cost of $12,565/ton over existing ESP controls. The applicant did not evaluate replacement of the ESP but instead the addition of fabric filters.

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 Northeastern Power Plant 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 Northeastern Power Plant 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 Northeastern Power Plant, as shown in Figure 1 below.

Only those Class I areas most likely to be impacted by the Northeastern Power Plant 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.

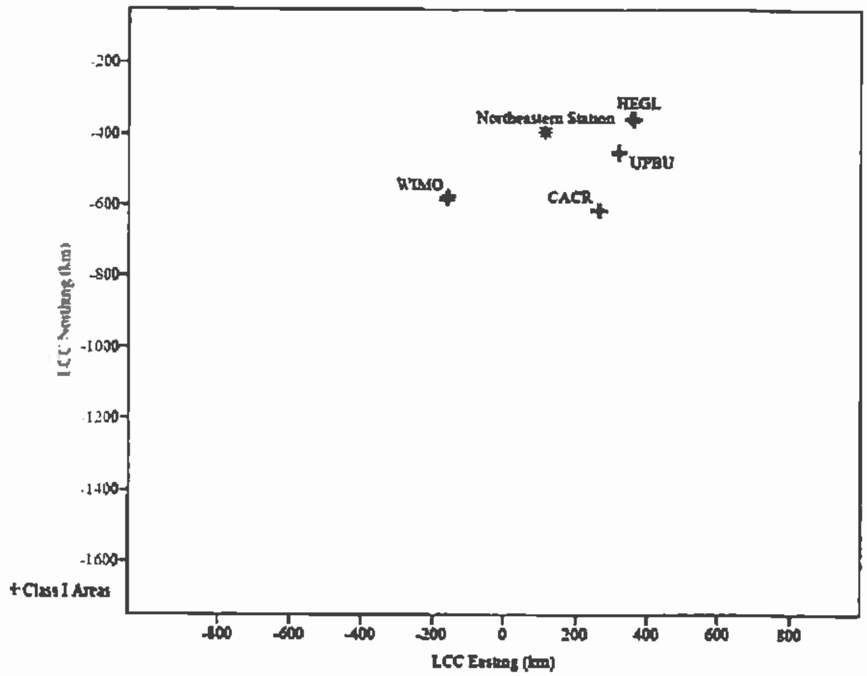

Figure 1: Plot of Facility location in relation to nearest Class I areas

REFINED MODELING

Because of the results of the applicants screening modeling for the Northeastern Power Plant, AEP-PSO 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 Northeastern Power Plant 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 15: 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 16: 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, 1000, 2000, 3500
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model outputs	14 km (MM5 data)
RMAX1	Maximum radius of influence	20 km

Variable	Description	Value
	(surface layer, 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.

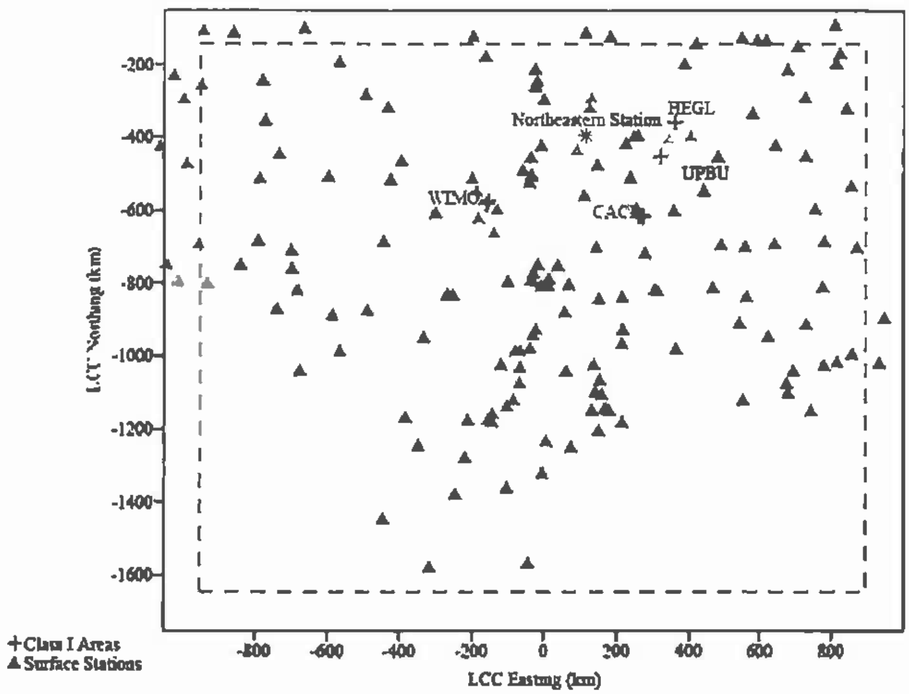

Figure 2: Plot of surface station locations

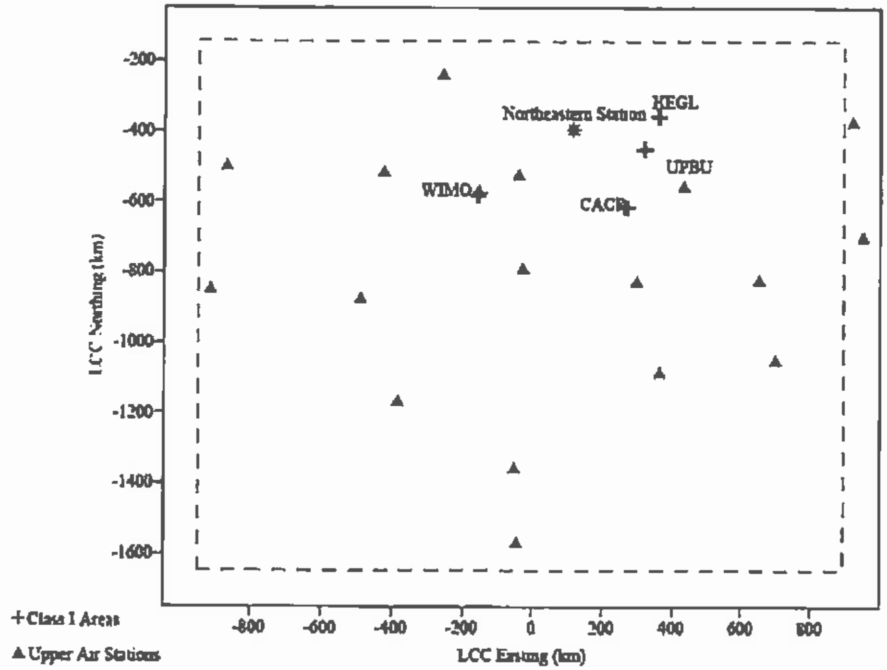

Figure 3: Plot of upper air station locations

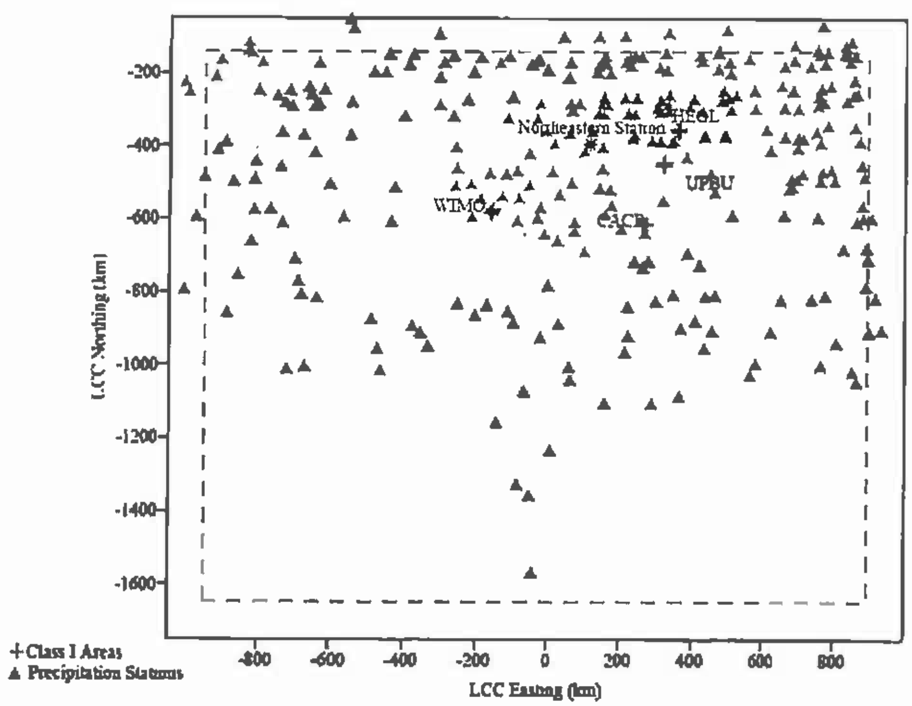

Figure 4. Plot of precipitation observation stations

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. Maximum 24-hour heat inputs and emission rates for the baseline emission calculations were established based on data from the years 2002 to 2005.

Baseline source release parameters and emissions are shown in the table below, followed by tables with data for the various control options. No attempt was made by the applicant to estimate the increase in sulfate emissions that would result from operations of SCR, and as a result the visibility improvement for those scenarios may be overestimated by some undetermined amount.

Table 17: Source Parameters

Parameter	Baseline[1]		
	Natural Gas-Fired Unit 2	Coal-Fired Unit 3	Coal-Fired Unit 4
Heat Input (mmBtu/hr)	4,767	5,812	5,594
Stack Height (m)	56	183	183
Stack Diameter (m)	5.49	8.23	8.23
Stack Temperature (K)[2]	394	424	415
Exit Velocity (m/s)[2]	16.29	18.97	17.46
Baseline SO_2 Emissions (lb/mmBtu)	0.0006	1.05	1.06
Dry FGD SO_2 Emissions (lb/mmBtu)	--	0.15	0.15
Wet FGD SO_2 Emissions (lb/mmBtu)	--	0.063	0.063
Baseline NO_X Emissions (lb/mmBtu)	0.71	0.536	0.491
LNB/OFA NO_X Emissions (lb/mmBtu)	0.28	0.15	0.15
LNB/OFA + SCR NO_X Emissions (lb/mmBtu)	0.05	0.054	0.049
ESP (Baseline) PM_{10} Emissions (lb/mmBtu)	0.007	0.025	0.040
FF PM_{10} Emissions (lb/mmBtu)	--	0.009	0.008

[1]Baseline emissions data were provided by AEP-PSO. 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 at that emission rate.

[2]Temperature and Velocity were decreased for DFGD and WFGD evaluations. For DFGD, stack temperature was modeled at 349 K and velocity decreased to 15.6 m/s for Unit 3 and 14.67 m/s for Unit 4. For WFGD, stack temperature decreased to 332K and velocity decreased to 14.86 and 13.96 for Units 3 and 4 respectively.

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 18: 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 19: CALPUFF Visibility Modeling Results for Northeast Units 3 and 4- NO_X

Class I Area	2001 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	0.468	0.402	0.775	0.548
Caney Creek	0.994	0.714	1.029	0.912
Upper Buffalo	0.883	0.42	0.442	0.582
Hercules Glade	0.644	0.345	0.296	0.428
Scenario 1- Combustion Control- LNB/OFA				
Wichita Mountains	0.136	0.116	0.223	0.158
Caney Creek	0.301	0.213	0.293	0.269

Upper Buffalo	0.259	0.124	0.131	0.171
Hercules Glade	0.191	0.102	0.086	0.126

Modeling for SCR controls resulted in an approximate 66% reduction in visibility impairment from scenario one.

Table 20: CALPUFF Visibility Modeling Results for Northeast Units 3 and 4- SO_2

Class I Area	2001 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	1.123	0.819	1.836	1.260
Caney Creek	1.322	1.186	1.245	1.251
Upper Buffalo	0.993	0.683	1.227	0.968
Hercules Glade	1.071	0.626	1.197	0.965
Scenario 1- Dry FGD				
Wichita Mountains	0.164	0.129	0.282	0.192
Caney Creek	0.207	0.199	0.190	0.199
Upper Buffalo	0.141	0.098	0.138	0.126
Hercules Glade	0.138	0.088	0.159	0.128

Wet FGD reduced visibility impairment by a further 50% over Dry FGD. This decreased degradation improved visibility by less 0.12 dv on the 98th percentile days and is considered an insignificant change.

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.

Table 21: CALPUFF Visibility Modeling Results for Northeast Units 2 NO_X

Class I Area	2001 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	0.366	0.247	0.489	0.367
Caney Creek	0.809	0.66	0.569	0.679
Upper Buffalo	0.541	0.246	0.269	0.352
Hercules Glade	0.495	0.275	0.266	0.345
Scenario 1- Combustion Control- LNB/OFA				
Wichita Mountains	0.144	0.099	0.19	0.144
Caney Creek	0.332	0.267	0.231	0.277
Upper Buffalo	0.218	0.099	0.108	0.142

Hercules Glade	0.195	0.111	0.108	0.138

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 three units at the Northeastern Power Plant.

NO_X

New LNB with OFA is determined to be BART for NO_X control for Units 2, 3 and 4 based, in part, on the following conclusions:

1. Installation of new LNB with OFA was cost effective at an average cost effectiveness of $303-313.
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 Units 3 and 4 and 0.28 lb/mmBtu on Unit 2 are justified meet the presumptive limits prescribed by EPA.

LNB with OFA and SCR was not determined to be BART for NO_X control for Units 2, 3 and 4 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 3 and 4 are on average $290,000,000. Based on projected emissions, SCR could reduce overall NO_X emissions from Northeast Units 3 and 4 by approximately 4,120 TPY beyond combustion controls; however, the incremental cost associated with this reduction is approximately $11,013/ton. SCR controls on Unit 2 would result in an incremental cost of $13,989.
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 3 and 4 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 and Sooner facilities. Cost estimates for the AEP-PSO Northeastern facility continue to be lower on a capital and annualized basis, but are comparable to the costs documented by OG&E. The substantiated AEP-PSO estimate for both boilers at $546,700,000 is $209,240,000 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 ($273,350,000). 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 22: 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 AEP-PSO units after adopting and annual average emission rate of 0.55 lb/mmBtu would be about 55 to 185% higher than the other units listed, i.e., less cost effective.

The average cost effectiveness at Northeastern for DFGD is $3,294 per ton of SO_2 removed from the present baseline and $6,146 per ton from the lower sulfur coal baseline for each unit over a twenty year operational life. The cost of add-on controls above and beyond lower sulfur coal at the Northeastern 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 Northeastern Facility was anticipated to reduce impairment by 3.97 dv. Importantly, the cost effectiveness of that improvement is calculated to be $21,829,547/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 Northeastern station is located with 300 km of 3 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 5.9 times more cost effective than DFGD controls at the Northeastern 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 AEP-PSO 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 AEP-PSO 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 AEP-PSO facility for at least 20 years and beyond. BART is the use of low sulfur coal (0.55 lb/mmBtu- annual average)..

Wet FGD was not determined to be BART for SO_2 control for Units 3 and 4 based, in part, on the following conclusions:

1. The cost of compliance for installing WFGD on each unit is higher than the cost for Dry FGD. Based on projected emissions, WFGD could reduce overall SO_2 emissions from Northeast Units 3 and 4 by approximately 3,200 TPY beyond dry scrubbers; however, the incremental cost associated with this reduction is approximately $6,356/ton without appreciable visibility improvement.
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. Wet 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.

PM_{10}

The existing ESP control is determined to be BART for PM_{10} controls for Units 3 and 4 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 23: Unit-by-unit BART determinations

Control	Unit 2	Unit 3	Unit 4
NO_X Control	LNB with OFA	LNB with OFA	New LNB with OFA
Emission Rate (lb/mmBtu)	0.28 lb/mmBtu (30-day rolling average)	0.15 lb/mmBtu (30-day rolling average)	0.15 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	1331 lb/hr (30-day rolling	716 lb/hr (30-day rolling	716 lb/hr (30-day rolling

	average)	average)	average)
Emission Rate TPY	5,830 TPY (12-month rolling)	6,274 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	--	3,104 lb/hr (30-day rolling average)	3,104 lb/hr (30-day rolling average)
Emission Rate (lb/mmBtu)	--	0.55 lb/mmBtu (12-month rolling average)	0.55 lb/mmBtu (12-month rolling average)
Emission Rate (TPY)		23,006 TPY	
PM_{10} Control[1]	--	ESP	ESP
Emission Rate (lb/mmBtu)	--	0.1 lb/mmBtu (3-hour rolling average)	0.1 lb/mmBtu (3-hour rolling average)
Emission Rate lb/hr	--	478 lb/hr (3-hour rolling average)	478 lb/hr (3-hour rolling average)
Emission Rate TPY	--	4,183 TPY (12-month rolling average)	

[1]Current emissions limits for ESPs are based on minimum NSPS requirements for front half catch and do not reflect the true emissions. As part of the permitting process, AEP-PSO will be required to propose emission limits for both front and back half, which is reflective of the control technology and consistent with the performance tests.

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 Northeastern Units 3 and 4 install DFGD with SDA for SO_2 control or meet the corresponding SO_2 emission limits listed below by December 31, 2018 or comply with the approved alternative described in section G (Greater Reasonable Progress Alternative).

Table 24: Unit-by-unit Contingent **BART determinations**

Control	Unit 3	Unit 4
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	478 lb/hr (30-day rolling average)	478 lb/hr (30-day rolling average)
Emission Rate TPY	2,091 TPY	2,091 TPY

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 visibility improvement while simultaneously solidifying the use of a higher emitting technology from now into the foreseeable future.

G. GREATER REASONABLE PROGRESS ALTERNATIVE DETERMINATION

In lieu of installing and operating BART for SO_2 Northeastern Units 3 and 4, AEP-PSO may elect to implement a fuel switching alternative. The greater reasonable progress alternative requires AEP-PSO to achieve a combined annual SO_2 emissions limit (identified in table 25) by installing and operating DFGD with SDA on one of the two boilers and being at or below the SO_2 emission that would result from switching the remaining boiler to natural gas. Under this alternative AEP-PSO shall install the controls (i.e., DFGD with SDA or achieve equivalent emissions) by December 31, 2026. By adopting these emission limits, DEQ and AEP-PSO expect the cumulative SO_2 emissions from Northeastern Units 1 and 2 to be approximately 43% less than would be achieved through the installation and operation of DFGD with SDA at both units.

Table 25: SO_2 Emissions with Greater Reasonable Progress

	Northeastern
Parameter	Unit 3 and Unit 4
BART (Low Sulfur Coal)	23,006 TPY
Contingent BART (DFGD)	4,182 TPY
GRP (DFGD/Natural Gas)	2,400 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)

Northeastern Power Plant is a major source under OAC 252:100-8 Permits for Part 70 Sources. AEP-PSO 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 Northeastern Station. The permit application should contain PM_{10} and $PM_{2.5}$ emission estimates for filterable and condensable emissions.

VI. OPERATING PERMIT

The Northeastern Power Plant 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 2, 3 and 4 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
2	2	Babcock and Wilcox UP-60	4754	1970
3	3	Combustion Engineering #4974 SCRR	4775	1974
4	4	Combustion Engineering #7174 SCRR	4775	1974

   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. New Low-NO_X Burners,
      ii. Overfire Air.
   e. The permittee shall maintain the controls (Low-NO_X burners, overfire air and ESP) 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	Averaging Period
2	2	0.28 lb/mmBtu	30-day rolling

EU ID#	Point ID#	NO_X Emission Limit	SO_2 Emission Limit	Averaging Period
3	3	0.15 lb/mmBtu	0.65 lb/mmBtu	30-day rolling
4	4	0.15 lb/mmBtu	0.65 lb/mmBtu	30-day rolling

EU ID#	Point ID#	SO_2 Emission Limit	SO_2 Emission Limit	Averaging Period
3	3	0.55 lb/mmBtu	23,006 TPY	annual average
4	4	0.55 lb/mmBtu		annual average

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.