UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

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

Dear Mr. Terrill,

Thank you for the opportunity to comment on the draft revision of the Oklahoma Regional Haze State Implementation Plan (SIP). I appreciate the tremendous effort that has gone into the preparation of this document. My staff has reviewed the SIP and our comments are enclosed. We stand ready to assist the Oklahoma Department of Environmental Quality as you prepare the final document.

If you have any questions concerning these comments, please feel free to call me at 214-665-7242, or Joe Kordzi of my staff at 214-665-7186.

Sincerely,

Carrie Paige for

Guy Donaldson
Chief
Air Planning Section

Enclosure:

EPA Region 6 Comments on the Oklahoma Draft Regional Haze SIP
12/15/09

1. EPA Region 6 has submitted these comments on the Oklahoma draft Regional Haze State Implementation Plan (RH SIP) with the intention of addressing the more significant issues that could be identified considering the review time available. Due to time and resource constraints, it has not been possible to conduct a completely thorough review, particularly with regard to modeling. It is possible that additional concerns, not discovered during the review of this draft, will surface during the review of the final version of this SIP.

2. Although on page 68, ODEQ states that Appendix V, Section 2.1(b) through (h), are included in Appendix 6-1, it does not appear that is the case. ODEQ should ensure, with the submittal of the final SIP, it demonstrates it has followed the requirements of Appendix V to Part 51.

3. On page 35, ODEQ states that for the purposes of calculating natural conditions, it considered all organic carbonaceous particulate, coarse matter, and fine soils as natural and all sulfureous, nitrate, and elemental carbon particulate as anthropogenic. This assumption ignores fine soil contribution from agricultural practices, such as wind-blown dust from tilled fields. Historically, this has been a significant source of fine soil. On page 32, ODEQ expands this discussion as it relates to fire, stating it assumed an overwhelming majority of organic aerosols originate from natural sources or fires. It is unclear whether this assumption ignores organic carbonaceous contributions from non-natural sources, such as agricultural fires and fires used to clear rangeland. Because of the economic component associated with these fires, it is unclear how they can be considered natural. Consequently, Region 6 feels these assumptions have not been adequately justified. Also, these assumptions impact the requirement in 40 CFR 51.308(d)(3)(iv), which requires ODEQ identify all anthropogenic sources of visibility impairment considered by it in developing its LTS, including consideration of major and minor stationary sources, mobile sources, and area sources. On page 104, ODEQ states "Despite their prominence in the emissions inventory, agricultural burning and wildfires in Oklahoma do not contribute significantly to regional haze at the Wichita Mountains nor at any other Class I area." However, Region 6 notes that according to Tables IV-1, IV-2, and IV-8, fire emissions account for approximately 33% of Oklahoma's PM 2.5 emissions inventory with agricultural burning itself accounting for approximately 23%. It would therefore appear that anthropogenic sources of biomass burning emissions are a significant contributor to the state's PM 2.5 emission inventory. Especially when it is considered that much of these emissions usually occur within a few weeks in the spring or summer and are not evenly spread out over the year. Region 6 understands that ODEQ is presently developing a smoke management plan. We view this as very important tool in the control of these emissions and urge ODEQ to work with us in the finalization of this important document.

4. Section 51.308(d)(1)(iv) requires that ODEQ consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment for the Wichita

Mountains. According to Tables V-1-V-6, and as noted on page 66, Texas accounts for more sulfurous, nitrate, organic carbonaceous, elemental carbonaceous, and fine soil particulate sources of light extinction to the Wichita Mountains than do those source in Oklahoma, and is right behind Oklahoma in coarse particulate. Table V-8 also indicated the sulfurous sources from Louisiana and Indiana also account for more light extinction than do the sulfurous sources in Oklahoma. Appendix 10-1 contains several consultation letters between ODEQ and neighboring States regarding ODEQ's consultation efforts. However, despite the obvious contribution from Texas sources to the visibility degradation to the Wichita Mountains, it does not appear that ODEQ actually requested reductions from specific sources within Texas – only that it be consulted on BACT analyses for sources within 300 kilometers from the Wichita Mountains. We urge Oklahoma insure that Texas is aware its sources impacts and encourage reductions as necessary.

5. ODEQ should include in Section X and in Appendix 10-1 the details concerning its consultation with Louisiana, or discuss why it did not feel sources in Louisiana are not reasonably anticipated to cause or contribute to visibility impairment at Wichita Mountains, in fulfillment of Section 51.309(D)(1)(iv).

6. On page 69, ODEQ discusses how it identified which sources were BART-eligible, stating, "DEQ reviewed its emissions inventory and followed the steps listed in Subsection II.A of Appendix Y to 40 C.F.R. Part 51 to derive a list of BART-eligible sources." However, no other information was located that describes the steps ODEQ took to make this determination. ODEQ should expand this discussion, making particular reference to information sources (e.g., permit databases, surveys, etc.) and how it ensured all BART-eligible sources were identified.

7. On page 71, Table VI-3 lists BART-eligible sources that were granted waivers from BART via proposed permitted emission limits. The actual waivers in Appendix 6-3, all contain essentially the same language:

"The active Title V permit will now be modified to include requirements that the facility comply with the proposed changes/limits in the application within five years of the Regional Haze SIP approval by EPA. Also to be included, will be a requirement that the facility modify the operating permit to incorporate the proposed method of compliance with Appendix Y to Part 51, V. Enforceable Limits. The operating permit shall be modified no later than 6 months prior to the SIP approval."

Regarding this, ODEQ should address the following:

a) No information was provided that indicates what controls or practices would be necessary to comply with these new permit limits. ODEQ should ensure that if compliance is via relatively uncomplicated work practices or operational modifications that can be done in a relatively short period of time, the full five years is not granted. This is necessary in order to comply with

51.308(e)(1)(iv), which requires "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."

b) ODEQ should provide all modeling and technical evaluations necessary to document the amount of reductions necessary for these facilities to fall under the BART threshold of 0.5 dv.

c) On page 71, ODEQ makes the following statement regarding these facilities and BART enforcement:

"DEQ will issue enforceable Part 70 air quality permits requiring BART-eligible sources subject to BART to: (1) install BART and achieve the associated BART emission standards; or (2) "achieve greater reasonable progress toward natural visibility conditions" through an approvable alternative as provided for in 40 CFR § 51.308(e). Subject sources must achieve the BART emission standards referenced above or achieve the "greater reasonable progress" referenced above within seven (7) years from the date of submission of the Oklahoma Regional Haze SIP or within five (5) years of EPA's approval of the SIP, whichever is longer."

Regarding this, the following comments apply:

i) Any future alternative to BART, as contemplated under 40 CFR 51.308(e)(2), would require a SIP modification.

ii) Region 6 suggests the language "achieve greater reasonable progress," which is apparently offered as an alternative to the BART emission limits proposed in the SIP, be dropped to avoid confusion with the reasonable progress requirement of 51.308. If a permit condition results in less SO2, NOx, or PM control than was provided for in the SIP, it would require a SIP modification.

iii) A schedule of compliance with BART that provides for the operation of BART controls later than five years from EPA's approval of the SIP would not be in compliance with 51.308(e)(1)(iv). Note similar language is on page 79.

iv) The above comment concerning the review of the modeling not withstanding, ODEQ should understand that Region 6 will not be able to approve the Oklahoma regional haze SIP until we are assured there is an adequate enforcement mechanism in the SIP to ensure these sources are no longer subject to BART.

8. ODEQ should discuss why the BART NOx limit for the AEP/PSO Southwestern power station unit 3 is 0.45 lbs/MMBtu, and not a lower value. It appears from an examination of EPA's CAMD database, that the historical annual NOx emission rates from this facility for each year from 2000 – 2008 (except for 2008), are already lower than the proposed controlled BART rate, even considering the BART rate is a 30 day average.

9. ODEQ should discuss why the AEP/PSO Northeastern power station units 3 and 4, should not have a lower proposed BART SO2 limit than the presumptive limit of 0.15 lbs/MMBtu.

10. On page 76, ODEQ discusses additional information received for the OG&E Sooner and Muskogee coal fired EGUs. OG&E increased its cost effectiveness calculations for Dry FGD-SDA to a range of $9,625 to $10,843 per ton of SO2 removed and to a range of $10,271 to $11,490 per ton of SO2 removed for Wet FGD. Region 6 has reviewed the information that was provided for public review. Based on cost estimates we have for other similar units, we feel these cost are significantly inflated. We question the assumptions in cost that have been made in general and the cost assumptions for annual operating costs, including administrative costs, which are significantly out of proportion with other cost analyses for similar control installations. Region 6 understands the data to support this cost estimate has been identified by the source as proprietary in nature. EPA Administrator Jackson's priorities for regulatory decisions are they be transparent and meet the requirements of the law. Therefore, these principles of transparency and rule of law are one's Region 6 wants to ensure are met in this process. Therefore, we cannot base a decision regarding BART on data that is not available for public review. Because of the projected visibility benefits to multiple Class I areas that would result from the control of SO2 emissions at these facilities, the lack of support for OG&E's figures, and our feeling the true installed costs of these controls are much lower, Region 6 would likely not be able to approve the Oklahoma regional haze SIP without these controls. We note that the U.S. Fish and Wildlife have provided more detailed comments on the OG&E and PSO BART analyses. We share many of the concerns that they raised, but did not think it necessary to be as detailed in this comment letter.

11. One of the items that is briefly mentioned is that for some BART-eligible sources, no BART reductions were assumed in the Regional Modeling. It would be helpful to have a table summarizing for each BART-eligible source, what emission rates were assumed in the RH modeling. An additional table indicating if the source was subject to BART, or was able to model out of BART and/or include the final emission rates that are being made federally enforceable (either through permitting, or other methods). While the zero-out modeling bounds the impact, it would helpful to have a summary of additional emission rate changes that have not been take into account in the RH modeling analysis.

12. Within the body of the text in its reasonable progress section, beginning on page 96, ODEQ should provide references for the data contained in all the tables and figures (e.g., Table IX-1 Figure IX-1) that direct the reader to where the data can be found.

13. On page 99, ODEQ presents data in Table IX-3, that essentially shows the difference between its Reasonable Progress Goal (RPG) and the Uniform Rate of Progress (URP) is approximately equal to the visibility impact from sources outside of Oklahoma. Regarding this, ODEQ makes the statement: "The model-extracted data in Table IX-3 suggest that even complete elimination of all anthropogenic emissions in Oklahoma likely would fail to meet this uniform rate of progress." This zero-out run of Oklahoma's

emissions assumes no additional changes in upwind states. This is not a realistic assumption and it does bias the conclusion that removal of all Oklahoma sources would still likely fail to meet the uniform rate of progress goals. Further reductions in upwind states in addition to local measures could yield a result meeting the uniform rate of progress goal.

14. Region 6 was unable to locate ODEQ's response to the requirements contained in Sections 51.308(d)(1)(vi) and 51.308(d)(3)(v)(G).

15. Section 51.308(f) requires that ODEQ revise and submit its regional haze implementation plan revision to EPA by July 31, 2018 and every ten years thereafter. In response to this, ODEQ states on page 111, "DEQ awaits approval of this implementation plan before submitting any such revisions." ODEQ should clarify that it will comply with this requirement.

16. Section 51.308(d)(4)(v) requires that ODEQ submit an emissions inventory that must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. The ODEQ has supplied an inventory for the baseline year, and for 2018. EPA understands that the ODEQ has emission inventory data available for 2005 and requests that it be included in the SIP. The preamble to the 1999 Regional Haze Rule (64 FR 35745) clarifies EPA authority for requiring the emission inventory of the "most recent year for which data are available," under 51.308(d)(4)(v):

> "Requirements Under Section 110(a)(2) of the CAA. Visibility SIP submittals must document certain program infrastructure capabilities consistent with the requirements of section 169B(e)(2) and section 110(a)(2) of the CAA. Section 169(B)(e)(2) requires States to revise their section 110 SIPs to ''contain such emission limits, schedules of compliance, and other measures as may be necessary'' to carry out regulations promulgated pursuant to this section. The EPA believes that this language authorizes EPA to ensure that States review their existing program infrastructures to ensure that the types of elements required by section 110(a)(2) for programs addressing the NAAQS are also sufficient for adoption and implementation of SIP measures for regional haze. The final rule does not include specific provisions addressing all elements of section 110(a)(2). However, section 51.308(d)(4)(iv) of the final rule requires the State to maintain and update periodically a statewide inventory of emissions of pollutants that contribute to visibility impairment. Where a State is also revising its SIP to incorporate changes to address the PM2.5 NAAQS, many of these revisions may be sufficient to address both PM2.5 and regional haze. The EPA encourages States to consider the needs of both programs when updating the provisions required by section 110 of the CAA to minimize any administrative burdens."

EPA requests that the ODEQ contrast its 2005 emission inventory with that from its baseline year of 2002, and 2018, in order to serve as a check of the EI projection methodology.

17. In the modeling section, it would be helpful to note where the modeling files (RH and BART) can be accessed. Inclusion of a printout (or screenshots) of the list of documents available on the CENRAP and ODEQ websites and/or ftp sites that are being relied upon in the SIP would make a good attachment to the SIP narrative.

Sharon

RECEIVED

DEC 16 2009

AIR QUALITY

Chesapeake Energy Corporation

Comments to Regional Haze Implementation Plan
December 16, 2009

Chesapeake Energy Corporation ("Chesapeake") has reviewed the "Regional Haze Implementation Plan Revision" dated November 13, 2009 ("Plan"). Such Plan was prepared by the Oklahoma Department of Environmental Quality ("DEQ").

It is clear from DEQ's extensive study of the regional haze issue that emissions of sulfur compounds are primarily responsible for impacts to the Wichita Mountain Class I Area. Specifically, coal fired generation units account for the bulk of the impact. As a result, rather than requiring huge capital investment to Oklahoma coal-fired units that are more than 30 years old, such units should either convert to natural gas firing systems or be replaced with new natural gas fired generation units.

An immediate option is available to Oklahoma. A significant percentage of baseload generation can be supplied by existing underutilized natural gas generation facilities. For example, capacity utilization from combined cycle generation facilities in Oklahoma is typically less than fifty percent. Increased utilization of natural gas fired generation by the owners of the coal fired units would improve visibility at the Class I Area.

Oklahoma must begin to effectively address emissions from coal-fired electric generation plants in Texas. There are 17 coal-fired electric generation plants operating today in Texas and another 13 are currently in the permitting process or under construction. These facilities are culpable not only for visibility impacts but also for contributing pollutants that impair Oklahoma's ability to comply with National Ambient Air Quality Standards.

Chesapeake submits the following comments specific to the Plan:

1. The Plan states: "Inside Oklahoma, Texas alone contributes more to visibility impairment at the Wichita Mountains than Oklahoma does. Considering these results, any effective strategy for managing visibility impairment at the Wichita Mountains must address outside sources including regional and international transport." The document further concludes that "[s]ources in Oklahoma contribute less than one-seventh of the visibility impairment at the Wichita Mountains; **emissions from Texas alone account for almost twice the impairment as those from Oklahoma"** (emphasis added) See Also, Tables V-1, V-2, V-3, V-4 and V-5.

   Comment: The Plan fails to adequately address out-of-state sources that contribute to visibility impairment at the Wichita Mountains. DEQ should evaluate culpable out-of-state sources (in conjunction with an applicable state agency) with the same level of scrutiny as sources inside Oklahoma.

2. The Plan states: "Table V-8 indicates sulfureous emissions clearly most importantly impair visibility at the Wichita Mountains." The report continues by stating ". . . Texas sources bear culpability for the largest proportion of visibility impairment. In every category except course particulate matter, sources in Texas (and other states) notably contribute more than those in Oklahoma do.

   Comment: Most sulfureous emissions that impact visibility at the Wichita Mountains may be attributed to coal-fired sources (particularly coal-fired electric generation units). While the Plan acknowledges impact from out-of-state sources and to some extent, attempts to address this matter via consultation with Texas and agreement to allow Oklahoma opportunity to comment on pending Texas air permit applications (for sources within 300 km of the Oklahoma/Texas border), such approach is inadequate. This is particularly the case given DEQ is requiring excessively expensive "sulfur emission" controls on coal-fired electric generation units located within the state. (see comment below)

3. The Plan states: "In her letter dated 25 March 2008, Susanna Hildebrand, director of air quality division of Texas Commission on Environmental Quality, requested concurrence of Oklahoma that DEQ did not rely on any additional reductions from Texas sources in meeting reasonable progress goal at the Wichita Mountains. DEQ responded in a letter dated 25 April 2008, confirming that DEQ accounted for all expected reductions."

   Comment: In light of overwhelming evidence that Texas sources impact visibility at the Wichita Mountains, and given ~~the~~ potentially large financial impact on Oklahoma electric generation facilities and ratepayers, DEQ should have requested additional reduction from Texas sources to meet the reasonable progress goal.

4. As referenced in Table V1-6, DEQ specifies that Dry Flue Gas Desulfurization ("DFGD") be installed on the following coal-fired units:

OG&E Muskogee	Units 4 & 5
OG&E Sooner	Units 1 & 2
PSO Northeastern	Units 3 & 4

Comment: While Chesapeake acknowledges that DFGD technology would result in significant reductions of sulfur emissions, such will be accomplished only after extraordinary and unwarranted investment by ratepayers.

Chesapeake is aware of OG&E's estimation that scrubber capital cost on its affected coal units would total $1.527 billion. Further OG&E claims that it expects to incur annual operating and maintenance costs of $150 million. Finally, OG&E claims that Oklahoma ratepayers will be required to endure a $365 million rate increase. While DEQ may dispute OG&E's calculations, one fact is clear; the capital and annual O & M costs for DFGD are extremely high and would represent one of the largest capital investments undertaken in state history. Chesapeake believes that the expenditure of funds for this emission control equipment is imprudent. While it would undoubtedly be acceptable to DEQ, culpable coal-fired generation should focus on the development and utilization of more environmentally friendly electric generation units and fuel sources.

Thank you for allowing Chesapeake to provide comments to this important matter.

devon

William F. Whitsitt, Ph.D.
Executive Vice President
Public Affairs

Devon Energy Corporation
20 North Broadway
Oklahoma City, OK 73102

405 552 3556 Phone
405 552 1484 Fax
bill.whitsitt@dvn.com

December 16, 2009

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

Attn: Cheryl E. Bradley, Manager, Environmental Programs

Re: Support for OG&E Regional Haze State Implementation Plan Proposal

Devon Energy Corporation offers these comments in strong support of OG&E's alternative proposal to the draft Regional Haze State Implementation Plan (SIP) being considered by the Oklahoma Department of Environmental Quality (DEQ).

The OG&E proposal sets out a responsible, reasonable and common-sense process to meet the required "further progress" target of no man-made visibility impact established by the Clean Air Act. The proposal, if adopted by the DEQ, would allow OG&E to relatively quickly lower its annual sulfur dioxide (SO_2) emissions by reducing coal combustion and increasing use of available natural gas for base-load capacity. This would eliminate the need to install scrubbers that could cost \$1 billion to \$1.5 billion. The cost of which would have to be passed on to the OG&E ratepayers. As a side benefit, by reducing the use of coal and increasing the use of natural gas, OG&E will significantly reduce carbon dioxide (CO_2) emissions.

Natural gas is the cleanest fossil fuel. According to the U.S. Energy Information Administration, natural gas is twice as clean as coal. It emits a minuscule amount of SO_2 when combusted compared to coal (one pound per billion Btu for natural gas compared to 2,591 pounds for coal), which would drastically reduce SO_2 emissions to help meet the regional haze goals outlined in the draft SIP. In addition, natural gas is increasingly viewed as a real solution to reducing our country's carbon footprint. On a Btu equivalency basis, natural gas emits about half the amount of CO_2 as coal and according to OG&E's forecast, its alternative plan has the potential to reduce CO_2 emissions by over 11 million metric tons in the first 10 years and over 5 million metric tons per year for every year after 2026.

The substitution of coal with natural gas has a positive impact on regulated pollutant emissions as well. According to Department of Energy figures, the combustion of natural gas can reduce emissions of the ozone precursor nitrogen oxide as well as emissions of carbon monoxide by as much as 80 % when compared to coal. Further, the proposed fuel switch, when completed, could all but eliminate particulate matter emissions.

Thus, this alternative proposal to gradually replace coal with natural gas at four generation units makes sense because it will simultaneously allow OG&E to meet regional haze objectives, prepare the company for Federal GHG reductions and improve Oklahoma's air quality.

The natural gas needed to accomplish the OG&E objectives is available. The Potential Gas Committee at the Colorado School of Mines has estimated the United States has more than a 100 year supply of natural gas at current demand rates. The advent of new technology for the exploration and production of natural gas has allowed producers to develop new shale resources that will continue to increase supply in the U.S. These shale resources can increase near-term supply due to short drilling and completion times and very high initial production rates. They also contribute to long-term supply stability with up to a 40-50 year production life. These onshore resources are easier and less expensive to develop than offshore resources and are less affected by weather.

Oklahoma is a key contributor to natural gas supplies in the United States, and is helping improve our country's energy security. Oklahoma is one of the largest producers in the U.S. with an estimated natural gas production of 5 billion cubic feet a day (BCFD). Currently, Oklahoma exports 3.5-4.5 BCFD to other markets in the U.S., and its own shale gas resources will be a significant contributor to serving markets outside and within Oklahoma long into the future. For example, Oklahoma's Woodford shale could hold upwards of 100-200 trillion cubic feet of gas. By accepting the OG&E proposal to the draft SIP, the DEQ can help increase the local market for one of Oklahoma's most valuable natural resources, thus adding value to Oklahoma production which in turn will increase production tax revenues to the state treasury and royalties to state mineral owners.

Devon is a staunch advocate for greater use of natural gas for electricity generation, especially since only slightly more than 20 percent of installed gas generation capacity is being used. Natural gas can make important energy and environmental contributions now. It is the cleanest fossil fuel and is abundantly available in the United States. It can provide a clean energy source for electric power generation and can be a reliable backup for wind and solar.

Please accept this letter as support for the OG&E alternative proposal to the draft SIP for Regional Haze. Devon strongly believes this proposal is the best for the environment, the economy and for Oklahomans.

Sincerely,

December 16, 2009

Before the

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

COMMENTS

of

OKLAHOMA GAS AND ELECTRIC COMPANY

on

REGIONAL HAZE IMPLEMENTATION PLAN REVISION

Proposed by

The State of Oklahoma
Department of Environmental Quality

Draft of November 13, 2009

I. Executive Summary

On November 13, 2009, the State of Oklahoma issued its Draft Regional Haze Implementation Plan Revision (the "Revised SIP"). The Revised SIP requires, among other things, that Oklahoma Gas and Electric Company ("OG&E") install dry flue gas desulfurization technology with a spray absorber system ("Dry FGD" or "scrubbers") to control certain visibility-impairing emissions on four coal-fired generating units at OG&E's Muskogee and Sooner Generating Stations. Such a requirement is contrary to applicable law as scrubbers would not be cost effective on these units under Section 169A of the Clean Air Act.

Installation of scrubbers also would have a severe financial impact on OG&E, its customers and the Oklahoma economy. The installation of scrubbers is projected to cost more than $1 billion, which OG&E believes would be among the largest privately funded capital investments ever in Oklahoma. Operation and maintenance of the scrubbers would cost even more. OG&E estimates that the largest rate increase in its history would be required to recover from its customers the capital and operating costs of the scrubbers. Moreover, compelling OG&E to install scrubbers is also contrary to a national trend toward reducing carbon dioxide (“CO_2”) emissions from these types of facilities. Once OG&E expends more than $1.0 billion to install scrubbers, OG&E will be locked economically into maximizing the use of its coal-fired units for the foreseeable future.

The State of Oklahoma should instead implement the alternative proposal submitted by OG&E in September 23, 2009 to achieve compliance with regional haze targets for the four OG&E units. OG&E’s alternative proposal will ultimately achieve the same visibility improvement as set forth in the Revised SIP but in a cost effective manner. OG&E’s proposal will also give OG&E the flexibility to generate its power in the future using cleaner energy, such as natural gas and wind, that can be obtained from sources within the State of Oklahoma.

II. Introduction

OG&E submits these comments on the Revised SIP, which was drafted by the Oklahoma Department of Environmental Quality ("ODEQ") on behalf of the State of Oklahoma. The Revised SIP is fundamentally flawed as it relates to four of OG&E's coal-fired units located at the Muskogee and Sooner Generating Stations. Use of Dry FGD to control sulfur dioxide ("SO_2") emissions from the four affected units, as called for in the Revised SIP, is not cost effective and is not the Best Availability Retrofit Technology ("BART") for these units.

Using first the federally required methodology and, later, a more unit-specific approach, OG&E has demonstrated that the costs of Dry FGD at these units is unreasonably high in light of the low emission reductions achieved. OG&E urges ODEQ to implement OG&E's alternative proposal for regional haze compliance in the Revised SIP. (OG&E Alternative Regional Haze Proposal (September 23, 2009) ("Alternative Proposal"), attached hereto as Ex. 1.)

OG&E's proposal will ultimately achieve the same improvement in visibility as Dry FGD and gives the company flexibility to consider innovative ways to address air emissions from these units in the future, including the use of more natural gas and wind derived from sources within Oklahoma.

A. BACKGROUND ON THE REGIONAL HAZE RULE AND BART

Under the authority of the Clean Air Act, the United States Environmental Protection Agency ("EPA") issued the "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" on July 6, 2005 (the "Regional Haze Rule"). 70 Fed. Reg. 39,104 (July 6, 2005). The Regional Haze Rule requires that certain states, including Oklahoma, develop programs to assure "reasonable progress" toward a national goal of preventing any future, and remedying any existing, visibility impairment at nearly 156 federally protected parks and wilderness areas (called “Class I areas”) over an approximately fifty-year period. 42 U.S.C. § 7491.

The Regional Haze Rule further requires that certain sources of air pollutants install BART to control regulated emissions. 40 C.F.R. § 51.302. Individual states must submit implementation plans to eliminate, by 2064, man-made impacts on visibility in affected Class I Areas from sources within that state. The Revised SIP identifies sources that contribute to visibility impairment in Class I areas, identifies BART for certain of these units, and develops a set of rules for the installation of BART.

Under the Regional Haze Rule, sources that may be required to install BART are those sources: (i) that were in existence between August 7, 1962 and August 7, 1977; (ii) that have the potential to emit 250 tons or more of a visibility-impairing air pollutant; and (iii) whose operations fall within one or more of twenty-six listed categories, including electric power generation. 40 C.F.R. §51.302(c)(4)(iii). OG&E has nine sources located at its Seminole, Horseshoe Lake,[1] Muskogee and Sooner Generating Stations that meet these criteria and were therefore subject to BART review. The four coal-fired units at the Muskogee (Units 4 and 5) and Sooner (Units 1 and 2) Generating Stations are the primary subjects of this comment.

B. OG&E’s Muskogee and Sooner Generating Stations

OG&E’s Muskogee Generating Station is located at 5501 Three Forks Road near Muskogee, Oklahoma. This facility has a total of four electric generating units. The two subject units, designated as Units 4 and 5, are nominal coal-fired units. Construction of these units commenced in the early 1970s with Unit 4 coming on line in 1977 and Unit 5 in 1978. Both of these units are dry bottom tangentially-fired pulverized coal boilers and both fire sub-bituminous

[1] As set forth in the Revised SIP, air dispersion modeling showed that the BART-eligible units at the Horseshoe Lake Generating Station, Units 7 and 8, were exempt from BART. OG&E agrees with this assessment.

coal as their primary fuel. Units 4 and 5 are equipped with electrostatic precipitators ("ESPs") for particulate control.

OG&E's Sooner Generating Station is located at 10800 County Road 230 near Red Rock, Oklahoma. The Sooner station includes two nominal coal-fired units designated as Units 1 and 2. Both of these units began construction in the mid-1970s with Unit 1 coming on line in 1979 and Unit 2 in 1980. Both of these units are dry bottom tangentially-fired pulverized coal boilers. Like the Muskogee units, these units fire sub-bituminous coal as their primary fuel and both are equipped with electrostatic precipitators for particulate control.

C. OG&E'S COMMENTS ON THE REVISED SIP

As a preliminary matter, BART evaluations conducted for affected units at OG&E's Muskogee, Seminole and Sooner Generating Stations address three types of emissions that have the potential to affect visibility—nitrogen oxide ("NO_x"), sulfur dioxide ("SO_2"), and particulate matter ("PM"). The Revised SIP contains a number of requirements that address emissions of these substances from the various OG&E facilities, but not all of these requirements are the subject of this comment.

OG&E agrees with the Revised SIP on several points. First and with respect to NO_x emissions, ODEQ concludes in the Revised SIP that the installation of low NO_x combustion technology to minimize the creation of NO_x during combustion is BART for affected units at the Muskogee, Seminole and Sooner Generating Stations. (Revised SIP, App. 6-4 at lxiv, cxxx, clxvi.) Second and with respect to SO_2 emissions associated with the three natural gas-fired boilers at the Seminole Generating Station (Units 1, 2 and 3), ODEQ concludes that "[b]ecause 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." (*Id.*, App. 6-4 at cxi.) Third, and with respect to SO_2 emissions associated with the four coal-fired boilers at the Muskogee (Units 4 and 5) and Sooner (Units 1 and 2) Generating Stations, ODEQ determined that wet flue gas desulfurization technology was even more costly than Dry FGD, would achieve minimal incremental visibility reductions and was therefore not BART for these units. (*Id*., App. 6-4 at lxv, clxviii.) OG&E agrees with the Revised SIP on these points.

The Revised SIP, however, also concludes that SO_2 from four coal-fired units at the Muskogee (Units 4 and 5) and Sooner (Units 1 and 2) Generating Stations impair visibility at Class I areas and that BART for these units is the installation of Dry FGD. While OG&E does not dispute that these units are subject to BART, Dry FGD is not a cost effective control option and is therefore not BART for these units. As set forth below, the data shows that Dry FGD is extremely expensive and use of this technology on the four affected units will yield low actual emission reductions and minimal overall visibility improvement.

In addition to OG&E's comments with respect to Dry FGD, OG&E also has comments, among others, with respect to the following items: (i) PM emissions for the four affected units at the Muskogee and Sooner Generating Stations in the absence of Dry FGD; (ii) ODEQ's inclusion in the Revised SIP of a presumptive limit of 0.10 lbs/mmBTU for SO_2 control at the Muskogee and Sooner units; and (iii) ODEQ's use of an incorrect measure of baseline emissions when calculating cost effectiveness at Seminole Generating Station and recent changes in its assessment of modeled visibility impacts.

III. BART Evaluations Show that Dry FGD is Not Cost Effective and Therefore is Not BART for the Four Coal-Fired Units at Muskogee and Sooner

BART evaluations show that Dry FGD is not cost effective and is not BART for SO_2 control at the four coal-fired units located at OG&E's Muskogee (Units 4 and 5) and Sooner (Units 1 and 2) Generating Stations. As detailed below, cost effectiveness must be considered in any BART determination and EPA requires that the cost effectiveness analysis be done in accordance with the methodology set forth in Appendix Y to 40 C.F.R. Part 51.

OG&E conducted BART evaluations in May 2008 (the "May 2008 BART Evaluations") and in September 2009 (the "September 2009 BART Evaluations") using EPA's required methodology. (*See* Muskogee Generating Station Best Available Retrofit Technology Evaluation (May 6, 2008)[2]; Sooner Generating Station Best Available Retrofit Technology Evaluation (May 9, 2008)[3]; Best Available Retrofit Technology Determination Report for Sooner/Muskogee Generating Stations (Sept. 17, 2009), attached hereto as Ex. 2.) Using the proper baseline for emissions, these evaluations show that Dry FGD on the Muskogee and Sooner units will cost in excess of $10,000 per ton of SO_2 removed. (Ex. 2.)

Even when OG&E revised its cost calculation methodology in December 2009 to address ODEQ's comments regarding unit-specific costs associated with Dry FGD, the revised evaluations show that this technology is expected to cost at least $6,300 per ton of SO_2 removed. (December 2009 Budget Cost Estimates, attached hereto as Ex. 3.) Either way, these costs are unreasonable and far exceed the EPA estimated cost for this technology.[4]

---

[2] Available at http://www.deq.state.ok.us/aqdnew/permitting/applications/2005-271-TVR_M-1/index.htm (last visited on December 14, 2009).

[3] Available at http://www.deq.state.ok.us/aqdnew/permitting/applications/2003-274-TVR_M-2/index.htm (last visited on December 14, 2009).

[4] In its original draft SIP, circulated on October 5, 2009, ODEQ acknowledged a "maximum cost of $5,000 per ton of SO_2 or NO_x emissions reduced as the upper limit of cost effectiveness" when assessing reasonable progress for Wichita Mountains. (*Draft Regional Haze Implementation Plan*, State of Oklahoma at 102 (Oct. 5, 2009).) OG&E's estimated costs for Dry FGD at all four affected units are well above this threshold regardless of whether such costs were calculated using EPA's OAQPS Cost Control Manual or whether they were calculated using the more recent unit-specific approach. Moreover, even as to the $5,000 threshold, ODEQ has never explained how it arrived at that number, especially in light of EPA's prior guidance on this issue identifying much lower expectations for costs.

A. ODEQ Must Consider Cost Effectiveness In Its BART Determination

Before making a BART determination, ODEQ must consider the cost effectiveness of any proposed control technology. Section 169A of the Clean Air Act requires that states determine the appropriate level of BART control by considering: (i) the costs of compliance; (ii) the energy and non-air quality environmental impacts of compliance; (iii) any existing pollution control technology in use at the source; (iv) the remaining useful life of the source; and (v) the degree of improvement in visibility that may reasonably by expected as a result of such technology. The implementing EPA rule is identical. *See* 40 C.F.R. § 51.308(e)(1)(ii).

EPA's "Guidelines for BART Determinations Under the Regional Haze Rule" are set forth in Appendix Y to 40 C.F.R. Part 51 ("Appendix Y"). The purpose of these Guidelines is to help states "identify those sources that must comply with the BART requirement and . . . determine the level of control technology that represents BART for each source." 69 Fed. Reg. 25,184, 25186 (May 5, 2004). Appendix Y sets out the five basic steps to a BART analysis: (1) identify all available retrofit control technologies; (2) eliminate technically infeasible options; (3) evaluate control effectiveness of remaining control technologies; (4) evaluate impacts and document the results; and (5) evaluate visibility impacts. 40 C.F.R. Pt. 51, App. Y(II)(A).

Step four in the BART analysis establishes the methods to be used in evaluating cost impacts. *Id*. These methods specifically require a cost effectiveness calculation using estimates based on EPA's Office of Air Quality Planning and Standards ("OAQPS") Cost Control Manual "where possible" so that states can "maintain and improve consistency" in making BART determinations. 40 C.F.R. Pt. 51, App. Y(IV)(D); 70 Fed. Reg. at 39,166. EPA recently affirmed the use of the OAQPS Cost Control Manual for these purposes, stating that: "[t]he Air Pollution Cost Control Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices." 74 Fed. Reg. 44313, 44318

(August 28, 2009). Oklahoma incorporates Appendix Y into its visibility protection standards. *See* OAC §§ 252:2-100-8-73; 252:100-8-75.

Not only does Appendix Y establish Guidelines for cost effectiveness determinations, it also sets forth "presumptive" BART limits for electrical generating units based on their type and size. 40 C.F.R. Pt. 51, App. Y (IV)(E)(4). EPA established presumptive BART for the coal-fired units at Muskogee and Sooner as 95% SO_2 removal or an emission rate of 0.15 pounds of SO_2 emissions per million BTUs of heat input (0.15 lb/mmBTU). This presumptive emission rate can be achieved with the installation of Dry FGD. For units that are the size of OG&E's, EPA estimates that sources could install Dry FGD at an average cost of $919 per ton of SO_2 removed annually with an estimated cost range from $400 to $2,000 per ton of SO_2 removed annually, and that this would be cost effective under the BART analysis.[5] *See* 70 Fed. Reg. at 39,132. For OG&E's units, however, the cost of achieving the presumptive rate using Dry FGD is at least seven times greater than EPA's projected average cost of installing these controls.

B. BART Evaluations Conducted in May 2008 and September 2009 in Accordance with Appendix Y Show That Dry FGD is Not Cost Effective

In accordance with Appendix Y, OG&E followed the Cost Control Manual when evaluating the cost effectiveness of Dry FGD in May 2008 and September 2009. In those evaluations, OG&E clearly demonstrated that Dry FGD is not a cost effective option for controlling SO_2 emissions at the Sooner and Muskogee Generating Stations. ODEQ's own cost estimates for OG&E's units in the Revised SIP are arbitrary and capricious because they rely on general data, such as industry magazines and qualified studies, instead of EPA's Cost Control Manual or even unit-specific information presented by OG&E.

[5] The emission limit of 0.10 lb/mmBTU for SO_2 included in the Revised SIP is significantly more stringent than the presumptive limit established for these units by EPA and is not justified. The presumptive limit for these units should be 0.15 lbs/mmBTU and this is the subject of the additional comment below in Section VI.

As mentioned above, EPA's Cost Control Manual identifies the procedures and data necessary to calculate the cost effectiveness of control technologies on the basis of dollars per ton of pollutant removed. Pursuant to Appendix Y, annual emissions resulting from the use of a particular control device are subtracted from baseline emissions to calculate tons of pollutant controlled per year. *See, e.g.*, OAQPS Cost Control Manual at 2-34 through 2-37. Under EPA's Cost Control Manual, total annual cost is calculated by adding annual operation and maintenance costs to the annualized capital cost of an option with capital costs consisting of direct costs + indirect costs (including capital recovery costs) – recovery credits. *See* OAQPS Cost Control Manual at 2-7. In developing its costs for the Muskogee and Sooner units, OG&E followed the procedures established in the Cost Control Manual and also relied on detailed engineering estimates, vendor quotations for similar projects and equipment, and data from Sargent and Lundy's internal cost database.[6]

1. <u>The May 2008 BART Evaluations</u>

The May 2008 BART Evaluation for Muskogee Units 4 and 5 estimated that the average cost effectiveness of Dry FGD at these units was $4,554 per ton of SO_2 removed. (May 2008 BART Evaluation for the Muskogee Generating Station at 51.) These estimated costs are nearly five times the average cost projected by EPA for this technology and over twice as much as the upper limit of EPA's projected cost range. The May 2008 BART Evaluation was performed in accordance with the requirements of Appendix Y and used the emission factors and cost

---

[6] It has been suggested in meetings with EPA and ODEQ that the use of this database is somehow questionable because the confidentiality of the information it contains prevents its examination by the agencies and the public. As OG&E explains in these comments, numerous public sources of information corroborate the estimates derived from the database. In contrast, at a meeting with OG&E on November 3, 2009 and in a subsequent letter dated December 9, 2009, EPA representatives mentioned the existence of a recent government survey that developed average cost effectiveness information for BART evaluations. As shown in Exhibit 4 of these comments, OG&E made several requests to obtain this survey. To date, the survey has not been provided, nor has any explanation of the EPA's inability to provide the survey been given.

estimates set forth in EPA's OAQPS Cost Control Manual. The annual cost of Dry FGD at Muskogee was estimated to be $142,600,600 for both units. (*Id.*) Dry FGD was estimated to cost approximately $111,900,000 per deciview ("dv") of improvement. (*Id*. at 55.)

The May 2008 BART Evaluation for Sooner Units 1 and 2 estimated the annual cost of Dry FGD to be $4,797 per ton of SO_2 removed for both units. (May 2008 BART Evaluation for Sooner Generating Station at 49.) These estimated costs are five times the average costs projected by EPA for this technology and over twice as much as the upper limit of EPA's projected cost range. This BART Evaluation was done in accordance with the requirements prescribed by EPA in Appendix Y and used the emission factors and cost estimates set forth in EPA's OAQPS Cost Control Manual. The annual cost of Dry FGD at Sooner was estimated to be $147,045,200 for both units. (*Id.*) The cost effectiveness of Dry FGD there was estimated to be $125,700,000 per dv of improvement. (*Id.* at 54.)

2. The September 2009 BART Evaluations

On September 18, 2009, OG&E submitted the revised BART Evaluations for the affected units at Muskogee and Sooner. (September 2009 BART Evaluations, Ex. 2.) These evaluations showed average cost effectiveness for Dry FGD to be in the range of $9,842 to $10,004 per ton of SO_2 removed at Muskogee and $9,625 to $10,843 per ton of SO_2 removed at Sooner. (*Id*.) The revised evaluations use actual emissions data to establish an emissions baseline for cost effectiveness calculations in accordance with a determination that had recently been made by EPA. *See* 74 Fed. Reg. at 44,321. In August 2009 and in connection with EPA's review of the cost effectiveness analyses for the Salt River Project ("SRP") Navajo Generating Station in Arizona, EPA found that SRP's use of "the same 24-hour average actual emission rate from the highest emitting day used for its modeling inputs" was incorrect. *Id*. EPA revised SRP's calculations accordingly "by starting with baseline emission rates for NO_X averaged over 2004–2006 . . . ." *Id.* EPA's determination in the SRP context is in line with the agency's requirement that baseline emissions "represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. at 39,167.

Using actual baseline emissions instead of the highest modeled baseline emissions in the BART Evaluation calculation leads to a more accurate—and higher—cost effectiveness estimate for the four coal-fired units at Muskogee and Sooner. In the May 2008 BART Evaluations for both Muskogee and Sooner, the baseline emissions were developed from the visibility model that uses the highest 24-hour block emissions reported during the baseline period pursuant to the Acid Rain Program. As pointed out by EPA, however, using this methodology to calculate baseline annual emissions for BART cost effectiveness overestimates actual emissions and does not provide a realistic estimate of anticipated annual emissions from each source. In the September 2009 BART Evaluations, OG&E instead used its actual annual baseline emissions for 2004-2006.

The cost per ton of SO_2 removal at Muskogee is high primarily due to OG&E's use of sub-bituminous coal as its main fuel source for Units 4 and 5. This low-sulfur coal (0.20-0.37%) already has a low potential for uncontrolled SO_2 emissions (0.50-0.86 lb/mmBTU). For Unit 4, the average actual annual baseline emissions of SO_2 was determined to be 9,113 tons per year, with an average SO_2 emission rate of 0.507 lb/mmBtu. For Unit 5, the average actual annual baseline emissions of SO_2 was determined to be 9,006 tons per year, with an average SO_2 emission rate of 0.514 lb/mmBtu. This compares with the visibility model values of 17,282 and 18,362 tons per year, respectively, used for these units in the 2008 report. The combination of relatively low baseline SO_2 emissions, low baseline visibility impacts (less than 1.5 Δ-dv at all

Class I areas), and the distance to the Class I areas all contribute to the high cost effectiveness values associated with these units.

OG&E also utilizes sub-bituminous coal as its primary fuel source for Units 1 and 2 at the Sooner Generating Station. The average actual annual baseline emissions of SO_2 for Unit 1 was determined to be 9,394 tons per year, with an average SO_2 emission rate of 0.509 lb/mmBtu. The average actual annual baseline emissions of SO_2 for Unit 2 was 8,570 tons per year, with an average SO_2 emission rate of 0.516 lb/mmBtu. This compares with the visibility model values of 17,344 tons per year used for both of these units in the 2008 report. The low baseline emissions of SO_2 at Sooner Units 1 and 2, coupled with the high annualized capital cost for Dry FGD, causes the cost effectiveness values for these units to be high in much the same way it did for the Muskogee units.

Using Appendix Y and the actual emissions baseline endorsed by EPA results in cost effectiveness values for Dry FGD at OG&E's Muskogee and Sooner units of approximately $10,000/ton. This is more than ten times the average cost expected by EPA for this technology and nearly five times as much as the upper limit of EPA's expected cost range.

3. ODEQ Cost Effectiveness Determinations Are Arbitrary and Capricious

ODEQ acknowledges in the Revised SIP that OG&E's cost estimation methodology generally follows EPA's Cost Control Manual. (*See* Revised SIP, Appendix 6-4 at xlviii, clii.) ODEQ also acknowledges the recent guidance from EPA clarifying that sources should use actual annual baseline emissions, rather than peak 24-hour emissions from visibility monitoring. (*See id.* at 77-78.) Nonetheless, ODEQ has rejected OG&E's estimates of the cost effectiveness of Dry FGD in favor of its own estimates, which are arbitrary and capricious.

ODEQ inappropriately relies on data from a 2003 National Lime Association Report, entitled "*Economics of Lime and Limestone for Control of Sulfur Dioxide,*" and an article in Power Magazine, to estimate the capital costs of Dry FGD for OG&E's units. (*See* Revised SIP, App. 6-4 at xlix, cliii.) However, neither resource was designed for use in developing budgetary cost estimates for particular units. (*See Abstract: Economics of Lime and Limestone for Control of Sulfur Dioxide* at 1.)[7] As more specifically detailed in Section 2.5 of the December 2009 Budget Cost Estimate, the National Lime Association Report was not intended to provide the basis for a project-specific capital cost estimate. Rather, the purpose of the report is to "compare costs of leading lime and limestone-based flue gas desulfurization (FGD) processes utilized by power generating plants in the United States." (*Id*.) Moreover, the 2003 National Lime Association Report is too outdated to provide useful data for estimating costs in 2009 or beyond. Likewise, the Power Magazine article that ODEQ relies on provides only average cost information but does not provide any information on cost distribution about the average. (*See Update: What's That Scrubber Going to Cost?* at 2.) The article explicitly states that that "average total installed costs reported by the survey respondents were expected to have wide variation . . ."[8]

Even more importantly, ODEQ's reliance on such materials completely disregards the requirements of Appendix Y, which requires states to use EPA's Cost Control Manual in making BART determinations "where possible." 70 Fed. Reg. at 39,104. OG&E's estimates, on the other hand, were developed in accordance with EPA's Cost Control Manual, as tailored specifically to the affected units. It is arbitrary and capricious for ODEQ to disregard these

[7] Available at http://www.lime.org/FGD/DePriest503.pdf (last visited on December 14, 2009).

[8] Available at http://www.powermag.com/environmental/Update-Whats-That-Scrubber-Going-to-Cost_1743.html (last visited on December 14, 2009).

estimates and instead rely on general information in industry reports and magazine articles in support of its BART determination for the four affected units.

4. The Federal Land Manager's Cost Effectiveness Estimates Are Similarly Flawed

Comments on the Revised SIP submitted by the Federal Land Managers ("FLM") on December 4, 2009 are similarly flawed. (*See* U.S. Fish and Wildlife Service ("USFWS") and National Park Service ("NPS") Comments Regarding Oklahoma Draft Regional Haze SIP ("FLM Comments") (Dec. 4, 2009).) The FLM inappropriately relies on a 2007 National Lime Association Report and the same Power Magazine article in support of its unfounded assertions that Dry FGD is cost effective for OG&E's affected units. (*Id*. at Attach., 2.) The FLM's reliance on this material is also arbitrary and capricious and also disregards Appendix Y.

Like the 2003 National Lime Association Report relied on by ODEQ, the 2007 National Lime Association Report that FLM cites was not intended to provide information for the cost of Dry FGD at any particular unit. Indeed, the author of that report explicitly "cautions the reader that the costs provided herein are not indicative of any cost you may actually achieve." (*FGD Technology Evaluation: Dry Lime v. Wet Limestone FGD* at 2 (March 2007).)[9] The Power Magazine article that FLM relies on is likewise inappropriate for the reasons discussed above.

Not only does the FLM inappropriately rely on generalized data instead of EPA-required methodology in reaching its own cost effectiveness numbers, but it also makes unsupportable assertions about the data provided by OG&E. In particular, the FLM argues that: (i) construction costs will be lower in 2012 than they were from 2007-2008; (ii) Dry FGD will be able to achieve a higher reduction efficiency than OG&E recognizes; and (iii) OG&E should

[9] Available at http://www.lime.org/FGD/FGDTechEvalDryLimevWetLimestoneFGD11311001.pdf (last visited on December 14, 2009).

consider whether FGD can be implemented without replacing the existing ESPs with a fabric filter to save money. (FLM Comments at Attach., 2-4.) Each of these arguments is problematic.

First, FLM's conclusion that future construction costs will be lower in 2012 is based exclusively on speculation about generalized trends in construction prices. In support of this assertion, FLM makes the unsubstantiated claim that "[a]ll of the reasons that caused [FGD] construction costs to dramatically escalate in the 2007-2008 period are abating." (*Id*. at Attach., 1.) OG&E has developed unit-specific cost estimates that account for fluctuating costs of various FGD components. These estimates, which are based on actual data, show that scrubbers are not cost effective.

Second, the removal efficiency presented by FLM is not achievable because FLM has failed to account for the already-low sulfur content of OG&E's fuel. The guaranteed efficiency of Dry FGD depends on inlet sulfur and the lowest SO_2 emission (floor) that will be guaranteed by the FGD supplier. FGD suppliers typically have not guaranteed below 94% SO_2 removal efficiency, or 0.08 lb/mmBtu, whichever is achieved first, at existing units. The low sulfur coal used by OG&E makes the lb/mmBtu value the applicable guarantee value. OG&E used 0.10 lb/mmBtu as the floor for a retrofit application to encompass all FGD suppliers with an additional margin of 0.02 lb/mmBtu to overcome system upsets and changes of atomizers. These were appropriate measures for estimating the removal efficiency of Dry FGD at OG&E's units, and they demonstrate that the removal efficiency presented by FLM is not achievable.[10] Dry FGD suppliers will not guarantee the removal efficiency suggested by FLM.

Third, the use of a baghouse downstream of a Dry FGD system has several advantages over using the existing ESPs in conjunction with a Dry FGD, as suggested by FLM.

[10] As discussed later in these comments, OG&E believes the appropriate SO_2 emission rate under BART for a facility that is required to install a scrubber is 0.15 lb/mmBTU.

Specifically, a Dry FGD/baghouse combination would remove more sulfur and reduce more emissions of HC1 and HF than Dry FGD with the existing ESPs. A new baghouse also could be completely installed without any tie-in outage. The modifications needed to tie in the existing ESPs, on the other hand, would need to take place during an outage, which would increase tie-in outage duration and increase power replacement costs. Adding Dry FGD upstream of the existing ESP would have yet another disadvantage—the amount of dust loading would increase in the ESP and the character of the dust would change, raising concerns about whether Sooner and Muskogee could continue to meet emissions limits for particulate matter without major ESP modifications.

5. <u>The U.S. Forest Service Lacks Support for its Comment Regarding Visibility Improvement Cost Effectiveness at OG&E's Units</u>

The U.S. Forest Service recently submitted comments on the Revised SIP asserting that "[a]ll Class I areas within 300 km should be used in the cost analysis to determine the cost per deciview of visibility improvement." (Comment Letter from N. Wagoner and J. Henry (Dec. 10, 2009).)[11] According to the Forest Service, OG&E "did not consider all four Class I areas where the Muskogee and Sooner Generating Stations are causing or contributing to visibility impairment." (*Id*.) The FLM also made this same point in its comments. (*See* FLM Comments, at Attach., 3.) In both cases, the comments are flawed.

As an initial matter, OG&E's units do not cause or contribute to visibility at "all four Class I areas" within 300 km, as the Forest Service suggests in its comments. EPA has determined that an individual source will be considered to "cause visibility impairment" if emissions from the source result in a change in visibility, measured as a change in dv's, that is

[11] The Forest Service's comments are available on ODEQ's website at the following address: http://www.deq.state.ok.us/aqdnew/RulesAndPlanning/Regional_Haze/us001.pdf. The copy available online appears to be incomplete. These responses to the Service's comment are based upon OG&E's interpretation of the incomplete copy that is available online.

greater than or equal to 1.0 dv on the visibility in a Class I area. *See* 70 Fed. Reg. at 39,120. An individual source is considered to "contribute to visibility impairment" if its emissions result in a dv impairment of greater than or equal to 0.5 dv in a Class I area. *Id*.

OG&E conducted visibility impact modeling to determine the baseline predicted maximum 98th percentile dv improvement impact from the Muskogee and Sooner units. This modeling showed that the Muskogee Station exceeded the 0.5 dv threshold only for the Upper Buffalo, Caney Creek, and Wichita Mountains Class I Areas. (May 2008 BART Evaluation, Muskogee Generating Station, at 4.) The maximum predicted visibility impact associated with the Sooner Station exceeded the 0.5 dv threshold only at the Wichita Mountains Class I Area. (May 2008 BART Evaluation, Sooner Generating Station, at 2.)

OG&E calculated average visibility improvement cost effectiveness (in dollars per dv per year) for its Muskogee units using the modeled visibility improvement from Dry FGD at the Caney Creek Wilderness Area. (*See* May 2008 BART Evaluation, Muskogee, Table 4-10.) OG&E relied on the Caney Creek improvement estimates because modeling indicated that the largest dv improvement from scrubbing would occur at Caney Creek. (*Id.*) When calculating average visibility improvement cost effectiveness for the Sooner units, OG&E relied on estimates for the nearest Class I area, and the only Class I area where Sooner units cause an impact equal to or greater than 0.5 dv—the Wichita Mountains Area.

Providing separate estimates for other Class I areas would not change the ultimate conclusion that scrubbers are not cost effective for the Muskogee units. Furthermore, the Forest Service and the FLM fail to cite any regulation directing OG&E to combine the visibility improvements at numerous Class I areas when calculating average visibility improvement cost effectiveness for its units. There is no such requirement. In fact, BART Guidelines specifically allow for sources to analyze visibility improvement for the highest-impacted Class I area only. 40 C.F.R. pt. 51 App. Y(IV)(D)(5) ("If the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further . . . ."). Other facilities have recognized this and calculated visibility improvement cost effectiveness in a manner that is consistent with OG&E's methodology. (*See, e.g.*, Revised BART Analysis for GGS, 44 (noting that incremental visibility impairment improvement costs were calculated "based on a modeled improvement of visibility impairment . . . at the worst-base Class I area, which is the Badlands of South Dakota").)[12]

C. ADDITIONAL COST ESTIMATES USING MORE SITE-SPECIFIC INFORMATION ALSO SHOW DRY FGD IS NOT COST EFFECTIVE

Neither EPA nor ODEQ questioned OG&E's methodology or its use of EPA's Cost Control Manual between the time OG&E submitted its 2008 reports and the time it filed revised emissions baseline information in September 2009. It was only after EPA and ODEQ recognized that OG&E's BART evaluations clearly showed that scrubbers were not cost effective that they asked for vendor quotations and other information to validate the 2008 cost estimates. Although OG&E's May 2008 and September 2009 BART Evaluations are valid and consistent with EPA requirements, OG&E agreed (at significant cost) to commission a detailed engineering study to provide site-specific budget cost estimates for installing scrubbers at the four affected units. (December 2009 Budget Cost Estimates, Ex. 3.) These revised cost estimates address ODEQ's and EPA's concerns that the Cost Control Manual's factors overstate the actual costs of Dry FGD at the Muskogee and Sooner units and confirm that Dry FGD is not a cost effective control technology on these units.

[12] Even if visibility improvements at all Class I areas were included when calculating costs per dv improvement, scrubbers still would not cost effective on a dollars-per-dv basis. This is because OG&E's facilities are relatively distant from the relevant Class I areas, compared to other facilities, and the costs of scrubbers are high. (*See* Dec. 2009 Budget Cost Estimates, Ex. 3 at 15.)

The December 2009 Budget Cost Estimates again show that Dry FGD is not cost effective. Costs range from \$6,348 to \$7,147 per ton of SO_2 removed for Sooner Units 1 and 2 and from \$7,221 to \$7,324 per ton of SO_2 removed for Muskogee Units 4 and 5.[13] (Ex. 3 at 12.) For Sooner, the total capital costs of installing Dry FGD at Units 1 and 2 is estimated to be \$584,589,400. (*Id.* at 4.) The combined annual cost of Dry FGD for both units at Sooner is estimated at \$93,664,600 with an average estimated cost of \$80,055,214 per dv of improvement. (*Id.* at 15.) For Muskogee, the total capital costs of Dry FGD are expected to be similar to the Sooner estimates. Total annual costs of Dry FGD at Muskogee are estimated at \$100,280,200 for both units. (*Id.*) Even as revised using a unit-specific approach, the estimated costs per ton of Dry FGD at these units are roughly seven times the average cost estimated by EPA for this technology and three times higher than the upper range of EPA's estimates.

The December 2009 Budget Cost Estimates were established using an approach whereby OG&E considered over seven hundred individual cost factors associated with the installation of Dry FGD at each of the affected units, ranging from the cost of the foundation for a lime storage silo to projected overtime for laborers. Operation and maintenance costs as well as administrative costs associated with Dry FGD were re-calculated using this approach as well. As more specifically set forth in the December 2009 Budget Cost Estimates, OG&E developed its estimates for each of these factors using project-specific vendor quotations and through the performance of preliminary project engineering. In addition, the December 2009 Budget Cost Estimates are based on current and projected capital cost estimates and also take into account

---

[13] Although OG&E believes that the Muskogee capital estimates are accurate, a complete estimate for these units had not been completed as of the date of this comment. OG&E is working with Sargent & Lundy to develop cost estimates for Muskogee in the same level of detail as it did for Sooner. OG&E will provide those estimates to ODEQ once they are available.

changed economic conditions since the original estimates were made in May 2008.[14] Even as revised using a unit-specific calculation methodology, the calculations establish that Dry FGD is not BART for the affected units at OG&E's Muskogee and Sooner Generating Stations.

IV. OG&E's Cost Effectiveness Estimates Are Consistent With Other BART Submittals

Comparing OG&E's cost effectiveness estimates for Dry FGD to those of other, similarly situated facilities reveals that OG&E's estimates are correct and that there are numerous differences between OG&E's BART-affected units and those of other facilities. As noted, the basic equation for calculating average annual cost effectiveness is to divide the total annual cost of a given control technology by the tons per year ("TPY") of SO_2 removed through the use of that technology (Total Annual Cost / TPY Removed). In this calculation, a higher number for TPY removed lowers the cost per ton of SO_2 removed, thereby improving cost effectiveness. Moreover, unique and facility-specific conditions can lead to differences in the total annual costs portion of the cost effectiveness equation.

OG&E's estimates of the costs per ton of installing Dry FGD at Sooner and Muskogee Generating Stations are higher than those of facilities operated by other companies. This is so largely because a variety of factors combine to increase the TPY removed from Dry FGD at other facilities well beyond the TPY removed at OG&E's units. Furthermore, the total annual costs estimated by OG&E in its BART Evaluations and subsequent site-specific budget cost estimate were appropriate for OG&E's units and are consistent with similar estimates for other

[14] Although OG&E's December 2009 Budget Cost Estimates reflect ODEQ's (and the FLM's) assumption that the costs associated with installing Dry FGD have decreased since 2008, construction costs are difficult to predict. For example, on November 25, 2009, American Municipal Power Inc. announced that it was suspending development of a coal-fired generating station in Ohio based on a recent and unexpected 37% increase in engineering, procurement and construction costs associated with the project. *See* http://www.cleveland.com/business/index.ssf/2009/11/american_municipal_power_will.html (last visited on December 15, 2009). Furthermore, if a revised CAIR regulation is released in 2010, the Dry FGD market could see escalations based on increased market demand.

facilities. Like other facilities' estimates, the OG&E estimates were based on the OAQPS Cost Control Manual. Even as supplemented with the site-specific Budget Cost Estimates in December 2009, OG&E's Evaluations show the costs of Dry FGD per ton of SO_2 reduced at OG&E's units far exceed the costs per ton accepted by other facilities.

A. DRY FGD RESULTS IN LOWER TPY REMOVED FOR OG&E'S UNITS COMPARED TO OTHER FACILITIES WITH LOWER COSTS PER TON

At least four factors affect any calculation of TPY removed through the use of a particular control technology on an electric generating unit: (1) the size of the unit; (2) the sulfur content of its fuel; (3) the unit's actual SO_2-emitting history; and (4) the measure used for calculating the unit's baseline annual emissions. Units with larger MW ratings and heat input capacities burn more coal per hour, which means there is more SO_2 to remove through the use of Dry FGD at those units. The same is true for the next two factors—more SO_2 is produced from the combustion of coal with higher sulfur content, and a unit's dispatch requirements will determine how often it operates and thus how much SO_2 is actually emitted. Finally, using an emissions baseline that overstates actual baseline emissions also will overestimate the TPY removed from Dry FGD.

In OG&E's case, all four factors contribute to the TPY removed from scrubbing at Sooner and Muskogee being roughly 35% to 75% lower than the estimated TPY removed through scrubbing at other facilities. Exhibit 5 shows how some of these factors relate to the TPY removed and the cost effectiveness of Dry FGD for OG&E's units, as compared with White Bluff Units 1 and 2, Nebraska City Station ("NCS") Unit 1, Gerald Gentleman Station ("GGS") Units 1 and 2, Boardman Power Plant Unit 2, and AEP's Northeastern Power Plant. In preparing Exhibit 5, OG&E selected facilities that were of roughly the same size as OG&E's units and that do not already use scrubbers as an existing control technology.

The first factor affecting TPY removed is the size of a unit. Compared to OG&E's units, all of the other facilities shown in Exhibit 5 except Northeastern burn more coal per hour as evidenced by their higher MW ratings and heat input capacities. Not surprisingly, these other facilities also have higher estimates of the TPY removed from Dry FGD.[15]

The second factor affecting TPY removed is the sulfur content of the fuel utilized by a unit. The facilities shown in Exhibit 5 use coal with higher sulfur content than the coal used by OG&E. OG&E uses coal with a sulfur content ranging from 0.5 to 0.86 lb/mmBtu (0.20 - 0.37% sulfur by weight). White Bluff, for example, used a much higher sulfur content for its coal—2.0 lb/mmBtu for Dry FGD (0.87% sulfur by weight). (*See* Revised BART Analysis for the White Bluff Steam Electric Station (Aug. 2008), at 3-5.) Using fuel with higher sulfur content contributes to more TPY removed.

The third factor contributing to higher TPY removed at other facilities is higher utilization. In its BART analyses, OG&E used actual, measured SO_2 emissions from its units to estimate TPY removed and, ultimately, the cost effectiveness of Dry FGD. These emissions necessarily reflect the actual dispatch requirements for a unit over the course of an entire year, including outages for repair and maintenance. NCS Unit 1 and GGS, on the other hand, assumed 100% utilization when calculating TPY removed even though the BART determinations for NCS Unit 1 and GGS expressly note that a capacity factor of 100% overstates TPY removed. (*See* Revised BART Analysis for GGS at 15 (Table 3); BART Analysis for NCS 1 at 12 (Table 2).)[16]

[15] Note that any differences in assumed control efficiency for Dry FGD are not large enough to significantly affect the overall cost effectiveness comparison for OG&E. The FLM, for example, recently recommended that a BART limit of 0.065 lb/mmBtu should be assumed for scrubbing at OG&E's Muskogee units, rather than 0.10 lb/mmBtu as assumed by OG&E, on the grounds that Dry FGD can achieve a higher control efficiency than OG&E recognizes. As noted above, the control efficiency recommended by FLM is not appropriate for OG&E's units. Even if it were, however, the difference between 0.10 lb/mmBtu and 0.065 lb/mmBtu would account for just a few additional TPY removed at OG&E's units. Even with the FLM's limit, Dry FGD would still result in much lower TPY removed for OG&E's units and much higher costs per ton compared to other facilities.

[16] Available at http://www.deq.state.ne.us/AirDivis.nsf/Pages/Haze (last visited on December 14, 2009).

Finally, using the wrong measure of baseline emissions can overstate TPY removed, thereby leading to unrealistically low estimates of cost per ton removed. As explained above, federal regulations and EPA's own practice establish that cost-effectiveness should be based on actual emissions. In the preamble to the BART Guidelines at Appendix Y, 40 C.F.R. Pt. 51, EPA explained that a "baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. at 39,167. Therefore, EPA noted that "in general, . . . you will estimate the anticipated annual emissions based upon actual emissions from a baseline period." *Id*. EPA recently again made this point when revising cost effectiveness calculations for the SRP's Navajo Generating Station to incorporate baseline emission rates averaged over a three year period. *See* 74 Fed. Reg. at 44,321.

In addition to these differences and contrary to EPA's regulations and clearly stated practice, all of the facilities shown in Exhibit 5 relied on some type of inflated measure of baseline emissions. OG&E also made this error in its original BART Evaluations for Sooner and Muskogee in May 2008. OG&E has since corrected the error by submitting the revised September 2009 BART Evaluations that rely on average actual emissions from the baseline period (as did EPA for the Navajo Generating Station). Other facilities have not made this same adjustment.

Overall, it makes sense that OG&E's estimates of the TPY removed from scrubbing are significantly less than the estimates developed for other facilities with larger units that are running harder, burning higher sulfur-content coal and using inflated measures of baseline emissions. The higher estimates of TPY removed at those other facilities also drives down their estimates of the cost per ton of Dry FGD.

B. IN ITS MAY 2008 AND SEPTEMBER 2009 BART EVALUATIONS, OG&E FOLLOWED THE SAME GENERAL APPROACH FOR ESTIMATING THE TOTAL ANNUAL COSTS OF DRY FGD AS OTHER FACILITIES

The May 2008 BART Evaluations contain reasonable estimates of the total annual cost of Dry FGD at Muskogee and Sooner. The same is true of the September 2009 BART Evaluations, which also reflect the appropriate measure of baseline emissions. As described previously, OG&E developed its cost estimates based on the EPA Cost Control Manual, engineering estimates, vendor quotes from similar projects and equipment, and Sargent and Lundy's internal cost database. Data was selected from these sources based on its appropriateness for use in estimating OG&E's costs for Dry FGD.

Other facilities used this same basic approach to estimate the total annual costs of installing and operating Dry FGD on their BART-eligible units. (*See*, *e.g.*, BART Analysis for NCS Unit 1 at 7-8 (Aug. 2007) (estimates were generally based on data from EPA's Cost Control Manual, with supplemental information provided from 2003 vendor-supplied quotations and general engineering estimates)[17]; Revised BART Analysis for GGS at 8-9 (Feb. 2008) (estimates based on EPA's data as refined through site-specific conceptual layouts and vendor budgetary quotes for major equipment costs).)[18]

Neither EPA nor ODEQ has suggested that OG&E's methodology in calculating cost effectiveness based on EPA's Cost Control Manual was incorrect. Instead, ODEQ has made the more general assertion that OG&E's costs seem high in comparison to the cost estimates offered by other facilities. (*See* Revised SIP, Appendix 6-4 at xlix, cliii.) These general assertions serve

[17] Available at http://www.deq.state.ne.us/AirDivis.nsf/23e5e39594c064ee852564ae004fa010/c03ae6a45b1e105286257443006512d5/$FILE/BART%20Analysis%20for%20NCS%20Unit%201.pdf (last visited December 15, 2009).

[18] Available at http://www.deq.state.ne.us/AirDivis.nsf/23e5e39594c064ee852564ae004fa010/c03ae6a45b1e105286257443006512d5/$FILE/Revised%20BART%20Analysis%20for%20GGS%20Units%201%20and%202.pdf (last visited on December 15, 2009).

little purpose. As shown in Exhibit 5, OG&E's total annual costs from its May 2008 Evaluations are only $3,000,000 to $6,000,000 higher than the estimated total annual costs of installing and operating Dry FGD on Units 1 and 2 at White Bluff. This difference can be accounted for through the combination of a variety of source-specific factors. It is clear that the costs projected by OG&E for its units are in the same general range as the costs actually projected at other facilities. As shown by the site-specific budget cost estimates, variations in the total annual cost of as much as 25% will not change the cost effectiveness determination.

C. NEW SITE-SPECIFIC BUDGET COST ESTIMATES VALIDATE THE CONCLUSION THAT SCRUBBERS ARE NOT COST EFFECTIVE.

To address comments from ODEQ and EPA, OG&E obtained the site-specific Budget Cost Estimates in December 2009. (Ex. 3.) Those estimates depart significantly from the methods in EPA's Cost Control Manual for determining costs associated with projected operations at the four coal-fired units at Sooner and Muskogee Generating Stations. While OG&E believes that ODEQ and EPA lacked any basis to require OG&E to depart from the published methodology for calculating costs, the site-specific Budget Cost Estimates nonetheless confirm that Dry FGD is not a cost effective option for OG&E's units. Exhibit 5 shows the costs per ton of Dry FGD are still significantly higher than the costs per ton accepted by other facilities. According to the site-specific estimates, the costs per ton of Dry FGD at OG&E's units exceed the costs per ton of Dry FGD at the other facilities shown in Exhibit 5 by roughly $3,000 - $5,000 per ton.

V. OG&E's Alternative Proposal Offers a Cost Effective and Better Way to Achieve the Same SO_2 Emission Reductions

In September 2009, OG&E offered a cost effective Alternative Proposal to achieve compliance with the Regional Haze Rule as it relates to the four coal-fired units at OG&E's Muskogee and Sooner Generating Stations. (Ex. 1.) The Alternative Proposal offers a cost effective approach to achieving the same level of emission reductions as would the installation of Dry FGD. Moreover, OG&E's September 2009 Proposal gives the company the flexibility to implement innovative technologies to control emissions from these units and meet future air standards. For these reasons, ODEQ should adopt OG&E's September 2009 Alternative Proposal in the Revised SIP.

A. OG&E'S ALTERNATIVE PROPOSAL

On September 23, 2009, OG&E submitted its Alternative Proposal for achieving "reasonable progress" in Oklahoma under the Regional Haze Rule. (Ex. 1) This proposal, which would be implemented in three steps, is based on incremental lowering of SO_2 emissions from the four affected units at the Muskogee and Sooner Generating Stations. Upon implementation of the first step, the affected units would not "cause" a visibility impact in a Class I area. Upon implementation of the second step, the units would not "contribute" to such an impact. Ultimately, OG&E proposes to lower its SO_2 emissions to achieve the same level of visibility improvement as would be achieved by the installation of Dry FGD. OG&E believes that, if adopted, this proposal would demonstrate compliance with the Regional Haze Rule in a cost effective manner.

As more specifically detailed in Exhibit 1, the three steps that OG&E proposes to achieve these emission reductions are as follows:

1. OG&E proposes to limit its SO_2 emissions to levels such that operation of the affected units will not "cause" a visibility impact in a Class I area beginning on the earlier of

January 1, 2016, or four years after SIP approval. By this time, OG&E would limit SO_2 emissions from all four affected coal-fired units to 0.65 lb/mmBtu on a 30-day rolling average basis and 0.55 lb/mmBtu on a 365-day rolling average. In addition, OG&E would accept enforceable annual SO_2 emission limits from the Sooner and Muskogee units (combined) as set forth in the table below. These limits represent an emissions decrease from emissions used in the visibility model of up to 46% for Sooner and of up to 65% for Muskogee.

	Muskogee 4 and 5 Combined Annual SO_2 Limit (tons/year)	Sooner 1 and 2 Combined Annual SO_2 Limit (tons/year)
Year 1	18,096	19,736
Year 2	16,635	19,318
Year 3	15,174	18,900
Year 4	13,713	18,482
Year 5	12,252	18,064

2. OG&E proposes to limit its emissions consistent with modeled emission impacts that do not cause or "contribute to" visibility impairment in a Class I Area beginning on the earlier of January 1, 2021, or nine years after SIP approval. By this time, OG&E would limit SO_2 emissions from the combined units at Sooner and Muskogee to 17,646 and 12,064 tons per year, respectively. These limits represent an emissions decrease of 48% for Sooner and 66% for Muskogee compared to the emissions used for visibility modeling. OG&E would also continue the SO_2 rolling average emission rates.

3. Beginning on the earlier of January 1, 2026, or fourteen years after SIP approval, OG&E would limit annual SO_2 emissions from the combined units at Sooner and Muskogee to 6,000 tons per year and 4,400[19] tons per year, respectively. This limit represents an

[19] The limit of 4,400 tons per year is a slight increase over the limit of 4,000 tons per year included in the September 2009 Alternative BART Proposal. The limit originally stated in the proposal was not consistent with the emission rate suggested in the May 2008 BART Evaluation for the installation of Dry FGD. The revised limit is consistent with the May 2008 BART Evaluation.

emissions decrease of 82% for Sooner and 88% for Muskogee compared to the emission rates used for visibility modeling—the same limit as would be achieved by installing Dry FGD on all four units.

OG&E's Alternative Proposal also offers the company flexibility for cost effective compliance. OG&E would have the ability to propose alternative emission limits that achieve the same improvement in modeled visibility impacts as the proposed limits. If OG&E believes the emission limits cannot be achieved cost effectively, OG&E could then ask ODEQ to approve alternate limits. In the absence of such explicit approval, however, OG&E would be obligated to comply with the already established limits.

B. OG&E'S ALTERNATIVE PROPOSAL GIVES OG&E FLEXIBILITY TO MEET FUTURE AIR STANDARDS

The approach proposed by OG&E in September 2009 would also give the company flexibility to employ innovative technologies developed over the life of OG&E's compliance obligations to control emissions from the four affected units and to meet future air standards. OG&E's proposal would allow the company the option to reduce SO_2 emissions in a variety of ways, including by the increased use of natural gas and wind generation, the installation of emission controls, or reducing coal combustion. The flexibility offered by this approach will allow OG&E the option to use local sources of energy thereby benefiting the State economy.

OG&E believes that it is prudent to anticipate that state and federal requirements regulating air emissions from coal fired electrical generating stations—including Maximum Achievable Control Technology standards and climate change legislation—will become effective in the next five to ten years. It is likely that these requirements will impact the economic and/or technical feasibility of particular emission controls on the affected units. OG&E's proposal will not only meet the requirements of the Regional Haze Rule for SO_2 emissions, but will give

OG&E the flexibility to employ innovative technology (including the use of alternative fuels) to meet future air requirements with respect to other emissions as well.

In addition, if Dry FGD is required, OG&E anticipates that it will be difficult for the company to obtain a construction permit for the scrubbers under the Prevention of Significant Deterioration ("PSD") tailoring rule for greenhouse gas emissions. It will take a significant amount of additional power to operate any scrubbers installed at the affected units. This power would be generated by burning additional fuel, which would likely increase greenhouse gas emissions (including CO_2 emissions) from the unit being scrubbed. It is unclear whether EPA would even issue OG&E a PSD permit under the current rules to cover these emissions. OG&E's alternative proposal does not present this issue.

Moreover, at a time when so much effort and attention in the environmental community is focused on reducing the use of coal, ODEQ's approach effectively compels OG&E to continue using coal to fuel these units for the foreseeable future. The installation, operation and maintenance of Dry FGD involves such a large capital investment—more than $1 billion within five years—that OG&E will have no choice but to continue to utilize coal as its primary source of fuel for a long time to come. Currently, OG&E fuels its units at Muskogee and Sooner with coal that is mined in Wyoming and shipped via rail. The State of Oklahoma has excellent resources for generating electricity with natural gas and wind. OG&E should have the flexibility to utilize these local energy sources at its plants in the future, while achieving the same reduction in impact on visibility.

OG&E's economic interests would arguably be better served by acquiescing to the Revised SIP. Under state law, OG&E would be entitled to charge its customers for its operating costs and capital costs for the scrubbers and to earn a return on the capital costs of the scrubbers.

However, this would require the largest rate increase in history for OG&E's customers. If ODEQ adopts OG&E's alternative proposal, any increased costs associated with using natural gas to generate electricity rather than coal will be recovered by OG&E on a dollar for dollar basis under its various fuel adjustment clauses and OG&E would not earn a return on these additional costs.

VI. Other Comments

A. IF SCRUBBERS ARE NOT REQUIRED, ESP IS BART FOR PARTICULATE MATTER EMISSIONS

The affected units at the Muskogee and Sooner Generating Stations are currently equipped with ESPs, and assuming that scrubbers are not required, the continued use of ESP is BART for PM control at these units. In the Revised SIP, ODEQ concludes that PM emissions are to be controlled by a fabric filter that is "integral to the design of the Dry FGD." For the reasons set forth herein, however, Dry FGD is not BART for these units. In the absence of Dry FGD, ESPs offer a cost effective approach to PM control.

In its May 2008 BART Evaluations for both Muskogee and Sooner, OG&E determined that baghouses would provide only an incremental reduction in PM/PM_{10} control compared to the existing ESP control systems.[20] Even without operation and maintenance costs and using higher baseline emissions, OG&E estimated the total capital costs of a retrofit baghouse system to be $104,000,000 per unit. Due to the high capital cost and the very low particulate emission reduction over ESP, the cost effectiveness for such a system would be well over $18,000 per ton of PM removed even without considering operations and maintenance costs. Adjusted to account for EPA's guidance on the use of average baseline emissions, this number would

[20] This discussion assumes that scrubbers are not installed. As discussed above, scrubbers would create additional particulate emissions compared to current operations and baghouses would be needed to achieve effective control if scrubbers are installed.

inevitably rise even higher. Accordingly, continued use of ESP for PM control is BART for these units assuming that scrubbers are not required, and currently permitted PM emission limits should apply.

B. THE REVISED SIP SHOULD REFLECT A PRESUMPTIVE LIMIT OF 0.15 LBS/MMBTU FOR SO_2 CONTROL

As discussed above, OG&E has presented an Alternative Proposal for making reasonable progress to address regional haze in a cost effective manner. Even if ODEQ ultimately does not accept that proposal, ODEQ must at least apply the EPA-established BART presumptive emission limit of 0.15 lb/mmBTU—and not its own significantly lower limit of 0.10 lb/mmBTU—for the Muskogee and Sooner units in its Revised SIP. Appendix Y sets forth the "presumptive standards [for these units that] were developed through a formal rulemaking process." 70 Fed. Reg. at 44,159. EPA has established that states "must require owners and operators of greater than 750 MW power plants to meet these BART emission limits." 70 Fed. Reg. at 39,131. Indeed, these "presumptive standards are 'mandatory' [and] must be applied" unless a source demonstrates that it would not be cost effective to apply these standards. 71 Fed. Reg. at 60,619; *see also* EPA Regulatory Impact Analysis for the Final Clean Air Visibility Rule, EPA-452/R-05-004 (June 2005).

EPA's perspective on the use of these presumptive limits is informed by Congressional intent. In discussing Section 169A(b)(1) of the Clean Air Act, which required the establishment of presumptive BART, the agency notes: "This statutory requirement clearly requires us to promulgate [presumptive] BART guidelines that the States must follow in establishing BART emission limitations for [over-750MW] power plants. … [T]he Act indicates that Congress intended the guidelines to be mandatory … with respect to 750 megawatt powerplants." 70 Fed. Reg. at 39,108. Hence, the Act's "unambiguous language leaves little room to dispute that the [presumptive BART] guidelines EPA is required to promulgate must be used by the states when making BART determinations for this class of sources." *Id*.

Presumptive limits of 0.15 lb/mmBTU established by EPA apply to each of the four coal-fired units at the Muskogee and Sooner Generating Stations. Accordingly, any BART determination for these units must be evaluated against this benchmark and not against the more stringent 0.10 lb/mmBTU benchmark used by ODEQ in the Revised SIP.[21]

C. OG&E RESERVES THE RIGHT TO COMMENT ON OUTSTANDING ISSUES CONCERNING THE BART DETERMINATION FOR SEMINOLE AND ODEQ'S ASSESSMENT OF VISIBILITY IMPACTS AT OG&E FACILITIES

On October 27, 2009, ODEQ issued Draft Permit to Operate No. 2003-400-TVR (M-1) for the Seminole Generating Station ("Draft Permit") along with a Memorandum explaining ODEQ's analysis of the corresponding permit application submitted by OG&E. OG&E submitted comments on the Draft Permit and ODEQ's Memorandum on November 5, 2009. OG&E's comments, attached hereto as Exhibit 6, raise two important issues that have not yet been resolved.

First, the current cost effectiveness estimates for the Seminole Generating Station are based on an incorrect measure of baseline emissions. (Ex. 6 at 21.) The May 2008 BART Evaluation for Seminole calculated baseline emissions according to the highest 24-hour actual emissions reported under the Acid Rain Program, rather than the annual average of actual emissions over the baseline period as required by EPA. As noted, OG&E made this same error

[21] ODEQ proposed a BART limit of 0.15 lb/mmBTU for AEP/PSO Northeastern Power Station Units 3 and 4 which are also coal-fired. There is no rational basis for applying limits to OG&E's units that are different from the limits proposed for the AEP/PSO Northeastern Power Station units. (Revised SIP at p. 73.) With respect to PM_{10}, the Revised SIP proposes an emission limit of 0.1 lb/mmBTU for the AEP/PSO Northeastern Power Station units in contrast to a proposed emissions rate of 0.015 lb/mmBTU for OG&E's units. OG&E believes that ODEQ does not have any rational basis for proposing different limits for these units. (*Id*.)

in its May 2008 BART Evaluations for Sooner and Muskogee Generating Stations but corrected the error when submitting the September 2009 BART Evaluations.

OG&E has not made a second, revised submission of cost effectiveness estimates for the Seminole Generating Station because ODEQ arrived at a reasonable BART determination for Seminole, notwithstanding the use of an incorrect emissions baseline. Nevertheless, OG&E continues to believe that the BART Determination for Seminole is contrary to EPA's regulations and guidance concerning the appropriate measure of baseline emissions when calculating the cost effectiveness of a control option. BART determinations should be made according to the EPA-required methodology.[22]

The second issue raised in connection with ODEQ's Draft Permit for Seminole deals with ODEQ's assessment of visibility impacts from Seminole. In its Memorandum accompanying the Draft Permit, and without prior discussions with OG&E on the topic, ODEQ provided estimates of visibility improvements expressed in Δ-dv and percentages that did not match the estimates in OG&E's May 2008 BART Evaluation. (Ex. 6 at 24.) ODEQ apparently decided at some point to use a different method for averaging modeled visibility impacts over the three-year baseline period based. Further consultation with ODEQ on this point is needed, and OG&E reserves the right to comment on ODEQ's new assessments for Seminole and any of the other facilities for which ODEQ has revised its assessments, once sufficient information on those revisions is made available to OG&E.

D. ODEQ'S ADOPTION OF THE REVISED SIP RAISES QUESTIONS REGARDING COMPLIANCE WITH THE OKLAHOMA ADMINISTRATIVE PROCEDURES ACT

[22] The data needed to develop the correct emissions baseline for the Seminole Generating Station is available on EPA's Clean Air Markets webpage at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard (last visited on December 15, 2009).

ODEQ proposes to adopt the Revised SIP for the purpose of implementing the BART rule (OAC 252:100-8, Part 11). *See* Regional Haze Implementation Plan Revision, dated 11/13/09, at 1-3. However, in doing so, ODEQ apparently does not intend to comply with the Oklahoma Administrative Procedures Act ("OAPA"). OG&E urges ODEQ to consider carefully whether its intended process effectively complies with the OAPA in implementing and revising an existing Rule and in prospectively setting policy for the State of Oklahoma that goes beyond determining BART controls for individual facilities. *See, e.g.*, 75 O.S. § 250.3(15); 75 O.S. § 302(D). The procedural requirements of the OAPA are designed to protect the due process rights of citizens who may be affected by agency actions, either through rulemaking procedures or individual proceedings where an affected party may present evidence and argument, and to the extent ODEQ adopts the Revised SIP and imposes the substantial costs on OG&E contemplated therein without the procedural safeguards contemplated by the OAPA, OG&E's rights would unquestionably be prejudiced. In the event ODEQ desires a specific request for an individual proceeding, OG&E requests such a proceeding prior to the final adoption of Dry FGD as the BART requirement applicable to the Muskogee and Sooner units.

VII. Conclusion

For the reasons set forth above, the State of Oklahoma should modify the Revised SIP by removing the requirement that OG&E install Dry FGD on four coal-fired units at its Muskogee and Sooner Generating Stations. The State should instead adopt the alternative proposal submitted to ODEQ by OG&E on September 23, 2009. The alternative proposal ultimately achieves the same degree of visibility reduction as Dry FGD, is cost effective, and offers OG&E the flexibility to use local, cleaner energy sources to generate electricity in the future.

Respectfully Submitted,

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

Exhibit 1

REGIONAL HAZE PROPOSAL

Oklahoma Gas and Electric Company (OG&E) submits this proposal to help the State of Oklahoma satisfy the standards established in the federal Clean Air Act for the improvement of visibility in national parks and wilderness areas (or Class I areas). The Clean Air Act requires the state, over approximately a 50-year period, to move toward the elimination of man-made impacts on visibility in Class I areas. For purposes of the OG&E facilities, the relevant Class I areas are Wichita Mountains National Wildlife Refuge, Caney Creek Wilderness Area, Hercules Glades Wilderness Area and Upper Buffalo Wilderness Area. EPA set the year 2064 as the deadline for achieving the target of no man-made impact on visibility in Class I areas.

Background and Process

The initial step that Oklahoma must take to meet the Clean Air Act target is the development of a set of rules that require certain sources to install Best Available Retrofit Technology (BART) by 2018. In addition to requiring BART, the rules have to demonstrate that Oklahoma is making reasonable progress toward achieving the target of no man-made visibility impact established by the Clean Air Act. After the state adopts the rules, they will be submitted to EPA for approval as part of the state implementation plan (SIP) under the Clean Air Act.

In May 2008, OG&E submitted BART evaluations for its affected generating units at Muskogee, Seminole and Sooner Stations. The units at Seminole Station use natural gas as their fuel and the affected units at Muskogee and Sooner Stations, which are Muskogee Units 4 and 5 and Sooner Units 1 and 2, are coal-fired.

The BART evaluations address two different types of emissions from these units that have the potential to affect visibility. The first type of emission addressed in the BART evaluation is nitrogen oxides or NO_x. The BART evaluations conclude that OG&E should install low NO_x combustion technology to minimize the creation of NO_x during combustion. One of the five factors considered in selecting BART is the cost effectiveness of available control technologies. The low NO_x combustion techniques are cost effective, ranging from $233 to $270 per ton of NO_x removed annually at the coal-fired units at Muskogee and Sooner stations. The NO_x control measures proposed as BART for the gas-fired units at Seminole will cost $1,675 per ton of NO_x removed annually. OG&E understands that the DEQ agrees with the proposed BART determination for NO_x at the affected Seminole, Sooner and Muskogee units.

The second type of emission addressed in the BART evaluation is sulfur dioxide or SO_2. EPA established a presumptive BART emission rate for the coal-fired units at Muskogee and Sooner of 0.15 pounds of SO_2 emissions per million BTUs of heat input. This emission rate can be achieved with the installation of dry flue gas desulfurization, which also is known as a scrubber. For units that are the size of OG&E's, EPA estimated that sources could install scrubbers at an average cost of $919 per ton of SO_2 removed annually, and EPA anticipated that the costs would range from $400 to $2000 per ton of SO_2 removed annually.

The presumptive BART emission rate for SO_2 does not apply if one performs a complete analysis of the five factors used to establish BART and determines a specific BART emission rate for the unit that considers its particular characteristics and circumstances. The BART analysis for the affected units at Muskogee and Sooner concludes that those units are different because they burn low sulfur coal that dramatically changes the cost effectiveness equation. For these units, scrubbers would have an average cost of $10,078 per ton of SO_2 removed annually (approximately ten times the average cost of $919 per ton estimated by the EPA), and the costs would range from $9,625 to $10,883 per ton of SO_2 removed annually depending on the particular unit. As a result, the BART evaluation concluded that scrubbers were not cost effective and recommended emission limits that require the units to continue burning low sulfur coal.

In the report from Sargent & Lundy that OG&E submitted to the DEQ on September 17, 2009 ("S&L Report"), the capital cost for scrubbers at the affected coal units (computed in accordance with EPA standards) was $1.527 billion. OG&E believes that, at $1.527 billion, this would be the largest privately-funded capital project in the history of the State of Oklahoma. Besides the capital costs, and as shown in the S&L Report, OG&E expects to incur approximately an additional $150 million annually to operate and maintain the scrubbers. For OG&E to recover these additional capital and operating costs along with the costs of NO_x controls, OG&E estimates that its rates to all customers would need to be increased approximately $425 million annually, of which approximately $365 million would need to be borne by OG&E's Oklahoma customers. While OG&E cannot estimate with precision the direct and indirect impacts on the Oklahoma economy of a $365 million annual increase in OG&E's electric rates, such rate increase would be the largest increase in the history of Oklahoma.

Visibility Impacts

Visibility is measured in a unit called a "deciview," which is basically a change in visibility that the human eye can detect. EPA's regional haze rules adopt a computer model for assessing visibility impacts. The model predicts a visibility impact measured as a change in deciviews (Δ-dv) in a particular Class I area that results from a particular unit's emissions. According to EPA, a source that is predicted to cause an impact greater than 1.0 Δ-dv is deemed to "cause" a visibility impact, and a source that is predicted to cause an impact greater than 0.5 Δ-dv is deemed to "contribute to" a visibility impact. With regard to NO_x, OG&E is proposing to install technology on the affected Seminole, Muskogee and Sooner units that has been modeled to limit the units' visibility impact to 0.14 Δ-dv or less for NO_x at each of the Class I areas.

For SO_2, the visibility impact model predicts that using low sulfur coal will still allow visibility impacts over 1.0 Δ-dv at three of the four Class I areas with the highest predicted impact being 1.471 Δ-dv. If OG&E installed scrubbers on all four units, the model predicts that the visibility impact would be decreased to less than 0.20 Δ-dv at each of the Class I areas. The BART portion of the regional haze rules, however, does not require emission controls that are not cost effective even if a source has an impact on visibility. And while the rules require a state to demonstrate that it is making reasonable further progress toward the goal of no man-made impact on visibility by 2064, EPA has stated that states have wide latitude in determining additional requirements for sources to achieve the reasonable progress goals. Here, too, cost effectiveness is one of the factors that states must consider in establishing these requirements.

As noted above, OG&E is convinced that the installation of scrubbers at the affected units is not BART as scrubbers would not be cost effective. OG&E is aware that potentially the DEQ and the EPA would not agree with OG&E's conclusion and, as a result, would seek to require OG&E to install scrubbers. In that event, OG&E believes that its only course would be to litigate the DEQ's and/or EPA's determination that scrubbers for OG&E's affected units are BART.

As an alternative, OG&E is proposing to control SO_2 emissions in three steps that are consistent with the state's reasonable progress goals of no man-made impact on visibility by 2064. In the first step, OG&E will limit SO_2 emissions from the affected units at Muskogee and Sooner to a level that will not "cause" a visibility impact. In the second step, OG&E will limit

SO_2 emissions from the units at Muskogee and Sooner to a level that both will not cause and will not contribute to a visibility impact. In the final stage, OG&E will limit SO_2 emissions from the units at Muskogee and Sooner to a level that would be attained through the use of scrubbers.

Timing

If Oklahoma does not have a SIP for regional haze that is approved by EPA before January 15, 2011, then EPA may issue a federal implementation plan (FIP). Once a SIP or FIP is in place, it will require BART controls to be installed as soon as practicable but no later than five years from the effective date. OG&E is proposing to implement all of the measures that constitute BART by the earlier of January 1, 2016 or four years after SIP approval.

There are two relevant milestones for evaluating whether Oklahoma is on the reasonable progress glide path toward the 2064 target of no man-made impacts on Class I areas. The first milestone is in 2018, which is the end of the period that the SIP is supposed to address. OG&E is proposing measures that will limit SO_2 emissions from the affected units at Muskogee and Sooner so that they do not "cause" a visibility impact greater than 1.0 Δ-dv by 2016. The second milestone is in 2028 when Oklahoma will be required to demonstrate again that it is on the reasonable progress glide path. OG&E is proposing measures that will limit SO_2 emissions from the units at Muskogee and Sooner so that they do not "cause" or "contribute to" a visibility impact greater than 0.5 Δ-dv by 2021 and so that they are equivalent to emissions if scrubbers had been installed by 2026. These proposals should sufficiently support Oklahoma's required showing of reasonable further progress.

Proposal

OG&E has developed a proposal to address SO_2 emissions that OG&E believes can be adopted by DEQ as a reasonable further progress goal under the regional haze rules. The proposal is based on a step-wise lowering of annual SO_2 emission limits to achieve concrete visibility results and, ultimately, the same visibility improvement that scrubbers would achieve. Absent new control technology or different fuel with substantially lower SO_2 emissions, the proposal will require the installation of scrubbers at all four affected units. The proposal is based on OG&E's expectation that the cost effectiveness of measures to address SO_2 emissions will improve in the future. If the cost effectiveness does not improve, the proposal gives OG&E the ability to ask DEQ to adopt alternative limits. To be effective, the proposal would have to be adopted by DEQ as part of the state implementation plan for regional haze and subsequently approved by EPA. OG&E reserves all of its rights in the event this proposal is not so approved.

OG&E proposes that DEQ should include these emission limits in the regional haze SIP:

i. Beginning on the earlier of January 1, 2016 or four years after SIP approval, OG&E would reduce NO_x emissions to 0.15 lb/mmBtu as proposed in the BART determination. The NO_x emission rate is based on installation of low NO_x burners and overfire air. OG&E would limit SO_2 emissions from all four affected coal-fired units to 0.65 lb/mmBtu on a 30–day rolling average basis and 0.55 lb/mmBtu on a 365-day rolling average. OG&E also would accept the following annual limits on SO_2 emissions from Sooner 1 and Sooner 2 combined and from Muskogee 4 and Muskogee 5 combined:

	Muskogee 4 and 5 Combined Annual SO_2 Limit (tons/year)	Sooner 1 and 2 Combined Annual SO_2 Limit (tons/year)
Year 1	18,096	19,736
Year 2	16,635	19,318
Year 3	15,174	18,900
Year 4	13,713	18,482
Year 5	12,252	18,064

These annual limits are consistent with the modeled 98th percentile Δ-dv impact for SO_2 emissions from each station being less than 0.75 at each of the four relevant Class I areas. This level was selected because a 1.0 Δ-dv impact is the level at which EPA deems a source to be causing a visibility impact. By limiting emissions to these levels, OG&E will be operating in a manner that does not cause a visibility impact in a Class I area. The limits for Sooner represent a 42% to 46% reduction from the baseline emissions of 34,071 tons per year used in the visibility model in the BART determination. The limits for Muskogee represent a 49% to 65% reduction from the 35,640 tons per year baseline used in the visibility model in the BART determination.

ii. Beginning on the earlier of January 1, 2021 or 9 years after SIP approval, OG&E would continue the NO_x control measures and SO_2 rolling average emission rates described in Part (i) and would limit annual SO_2 emissions from Sooner 1 and Sooner 2 combined to a total of 17,646 tons per year and from Muskogee 4 and Muskogee 5 combined to a total of 12,064 tons per year. These annual limits are consistent with the modeled 98th percentile Δ-dv impact for SO_2 emissions from each station being less than 0.50 at each of the four relevant Class I areas. This level was selected because it is the level at which EPA deems a source to be contributing to a visibility impact. By limiting emissions to these levels, OG&E will be operating in a manner that does not cause or contribute to a visibility impact in a Class I area. The limit for Sooner represents a 48% reduction from the baseline emissions of 34,071 tons per year used in the visibility model in the BART determination. The limit for Muskogee represents a 66% reduction from the 35,640 tons per year baseline used in the visibility model in the BART determination.

iii. Beginning on the earlier of January 1, 2026 or 14 years after SIP approval, OG&E would continue the NO_x control measures and SO_2 rolling average emission rates described in Part (i) and would limit annual SO_2 emissions from Sooner 1 and Sooner 2 combined to a total of 6,000 tons per year and from Muskogee 4 and Muskogee 5 combined to a total of 4,000 tons per year. These annual limits are consistent with the modeled 98th percentile Δ-dv impact for SO_2 emissions from each station being less than 0.20 at each of the four relevant Class I areas. This level was selected because it is the modeled visibility improvement that would be achieved by installing dry flue gas desulfurization on all four of the units. By limiting emissions to these levels, OG&E will be operating in a manner that protects visibility to the same degree that dry flue gas desulfurization would. The limit for Sooner represents a 82% reduction from the baseline emissions of 34,071 tons per year used in the visibility model in the BART determination. The limit for Muskogee represents a 88% reduction from the 35,640 tons per year baseline used in the visibility model in the BART determination.

OG&E may propose alternative emission limits that are consistent with achieving the same improvement in modeled visibility impacts. OG&E can comply with the SO_2 emission limits either by installing emission controls, reducing coal combustion, using coal with a lower sulfur content or using alternative fuels with lower sulfur content. To the extent that OG&E complies with the SO_2 emission limits by reducing coal combustion or using alternative fuels, there could also be a reduction in CO_2 emissions from Sooner and Muskogee. If OG&E believes that the emission limits provided in Part (ii) or Part (iii) cannot be achieved in a cost effective manner, OG&E will provide a report to DEQ no less than two years before the deadline for achieving such emission limit, and the report shall identify costs necessary to achieve the prescribed limit and propose an alternative limit that can be achieved in a cost effective manner. OG&E will be required to meet the prescribed emission limits unless DEQ approves the alternate limits proposed in the report.

Exhibit 2

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

RECEIVED
SEP 18 2009
AIR QUALITY

OG&E

September 18, 2009

HAND DELIVERED

Mr. Eddie Terrill, Director
Air Quality Division
Oklahoma Department of Environmental Quality
707 N. Robinson
Oklahoma City, Oklahoma 73101-1677

Subject: Best Available Retrofit Technology (BART) Determination Report
Oklahoma Gas & Electric Sooner/Muskogee Generating Stations

Dear Mr. Terrill:

Enclosed is a report by Sargent & Lundy updating the cost effectiveness calculations for sulfur dioxide (SO2) retrofit control technologies included in the Sooner and Muskogee Generating Station Best Available Retrofit Technology Evaluations dated May 27, 2008 and May 28, 2008, respectively (the "BART Evaluations"). We are providing this report now based on recent guidance from EPA on the appropriate methodology for cost effectiveness calculations. 74 Fed. Reg. 44313, 44321 (Aug. 28, 2009).

The cost effectiveness calculations in the BART Evaluations for OG&E have been updated using actual annual baseline emissions rather than the conservatively high baseline emission rate developed for visibility impact modeling. Using this methodology provides a more realistic estimate of actual baseline emissions and a more accurate cost-effectiveness calculation. EPA used this methodology in a recent notice of proposed rulemaking. 74 Fed. Reg. at 44321.

Using this methodology, the cost effectiveness of Dry FGD-SDA at the OG&E units ranges from $9,625 to $10,843 per ton of SO2 removed, and the cost effectiveness of the Wet FGD ranges from $10,271 to $11,490 per ton of SO2 removed. The revised cost effectiveness information for the OG&E stations supports a determination that low sulfur coal is BART for OG&E's units.

If you have any questions concerning the report please contact me at 553-3221.

Sincerely,

Ford Benham
Air Quality Supervisor

Enclosure

Sargent & Lundy LLC

Kenneth J. Snell
Senior Environmental Consultant
Phone (312) 269-2318
Fax (312) 269-2499
Kenneth.J.Snell@sargentlundy.com

September 17, 2009

Mr. Ford Benham
Air Quality Supervisor
OG&E Power Supply Services
P.O. Box 321, M/C 610
Oklahoma City, OK 73101-0321

Subject: Oklahoma Gas & Electric Company
Sooner and Muskogee Generating Stations
BART Cost Effectiveness Update

Dear Mr. Benham;

The purpose of this letter report is to update the cost effectiveness calculations for sulfur dioxide (SO_2) retrofit control technologies included in the Sooner and Muskogee Generating Station Best Available Retrofit Technology Evaluations dated May 27, 2008 and May 28, 2008, respectively (the "BART Evaluations"). The cost effectiveness calculations in the BART Evaluations for OG&E have been updated using actual annual baseline emissions rather than the conservatively high baseline emission rate developed for visibility impact modeling. Using this methodology provides a more realistic estimate of actual baseline emissions and a more accurate cost-effectiveness calculation. **Using this methodology, which has been recommended by EPA, the cost effectiveness of Dry FGD-SDA at the OG&E units ranges from $9,625 to $10,843 per ton of SO_2 removed, and the cost effectiveness of the Wet FGD ranges from $10,271 to $11,490 per ton.**

Guidelines for making BART determinations are included in Appendix Y of 40 CFR Part 51 (Guidelines for BART Determinations Under the Regional Haze Rule). 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.

Step 4 of the BART determination process includes an evaluation of potential impacts associated with the technically feasible retrofit technologies, including: (1) costs of compliance; (2) energy impacts; and (3) non-air quality environmental impacts. The cost impact evaluation examines the cost-effectiveness of each control technology, on a dollar per ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from baseline emissions to calculate tons of pollutant controlled per year. Annual costs are calculated by adding annual operation and maintenance costs to the annualized capital cost of an option. Cost effectiveness ($/ton) is simply the annual cost ($/yr) divided by the annual pollution controlled (ton/yr).[1] Baseline emissions should "represent a realistic depiction of anticipated annual emissions for the source."[2]

Baseline emissions used to calculate cost effectiveness in the BART Evaluations were based on the baseline emission rates (lb/hr) used to model visibility impacts. Baseline emissions used to model visibility impacts were based on the highest hourly emission rate (on a 24-hour calendar day average) that occurred from 2002-2005 for each unit. The highest 24-hour calendar day SO_2 emissions for each unit used to model baseline visibility impacts are shown in Table 1.[3] Baseline annual emissions used to calculate cost effectiveness were calculated using the highest 24-hour SO_2 emission rate and assuming a 90% capacity factor. Baseline annual emissions used to calculate cost-effectiveness are shown in Table 2.

Table 1
Highest 24-hour Calendar Day SO_2 Emissions (2002-2005)

Unit	Baseline 24-hr SO_2 Emissions (lb/hr)
Muskogee 4	4,384
Muskogee 5	4,657
Sooner 1	4,393
Sooner 2	4,410

Table 2
BART Cost Effectiveness Baseline Annual SO_2 Emissions

Unit	Baseline 24-hr SO_2 Emissions (lb/hr)	Maximum Heat Input to Boiler (mmBtu/hr)	Baseline SO_2 Emission Rate (lb/mmBtu)	Baseline Annual SO_2 Emissions (tpy)
Muskogee 4	4,384	5,480	0.80	17,282
Muskogee 5	4,657	5,480	0.85	18,362
Sooner 1	4,393	5,116	0.86	17,344
Sooner 2	4,410	5,116	0.86	17,344

1 See, 40 CFR Part 51, Appendix Y, Step 4.c.
2 70 FR 39167, July 6, 2005.
3 Baseline emission rates were included in Table 2-1 of the respective BART Evaluations.

Using this methodology to calculate baseline annual emissions for BART cost-effectiveness overestimates actual emissions from the units, and does not provide a realistic estimate of anticipated annual emissions from each source. Table 3 shows the calculated BART baseline annual emissions compared to the maximum annual emissions from each unit for the years 2002 through 2008. It can be seen that, in all cases, the calculated baseline annual emissions were at least 60% higher than the maximum annual actual emissions from each unit.

Table 3
BART Baseline Annual SO_2 Emissions v. Maximum Actual Annual SO_2 Emissions

Unit	Calculated BART Baseline Annual SO_2 Emissions (tpy)	Maximum Actual Annual SO_2 Emissions (2002 – 2008) (tpy)
Muskogee 4	17,282	9,775 (2006)
Muskogee 5	18,362	11,160 (2003)
Sooner 1	17,344	10,644 (2002)
Sooner 2	17,344	9,779 (2008)

A more accurate cost-effectiveness calculation would include a more realistic estimate of actual baseline emissions. In its review of the cost effectiveness calculations prepared by Salt River Project (SRP) to support the Navajo Generating Station's BART determination, EPA stated that "[i]n calculating the cost effectiveness, it appears SRP used the same 24-hour average actual emission rate from the highest emitting day used for its modeling impacts, rather than an annual average rate. Therefore, EPA has revised SRP's estimated NOx emissions reductions by starting with baseline emission rates for NOx averaged over 2004-2006..."[4] Average actual emissions from the unit should provide a more realistic estimate of baseline actual emissions, and a more accurate cost-effectiveness calculation.

To provide a more realistic estimate of anticipated annual emissions from each OG&E BART source, baseline emissions were recalculated as the actual average emission rate for the years 2004-2006. Revised baseline annual emissions, and corresponding average SO_2 emission rates, are shown in Table 4.

4 EPA, Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advanced Notice of Proposed Rulemaking, 74 Fed. Reg. 44313, August 28, 2009, at 44321.

Sargent & Lundy LLC

Oklahoma Gas & Electric Company
Sooner and Muskogee Generating Stations
BART Determination – Cost Effectiveness Update
September 16, 2009

Table 4
Revised BART Baseline Annual SO_2 Emissions

Unit	Average Annual SO_2 Emissions (2004-2006) (tpy)	Average SO_2 Emission Rate (2004-2006) (lb/mmBtu)
Muskogee 4	9,113	0.507
Muskogee 5	9,006	0.514
Sooner 1	9,394	0.509
Sooner 2	8,570	0.516

Lowering the baseline emission rates will not effect capital cost estimates prepared for the BART Evaluations. Capital cost estimates are based on the unit size, flue gas flow rates, and maximum design pollutant loading (i.e., the maximum 24-hour inlet rate). However, lower baseline emissions will result in a slight reduction in the annual variable O&M costs. For example, reactant costs and FGD byproduct disposal costs will vary depending on the baseline inlet SO_2 emission rate. To account for these changes, the BART cost-effectiveness calculations were redone using the lower, more realistic, baseline emission rates. Updated cost-effectiveness calculations for each unit are attached at the end of this report.

The cost effectiveness calculations in the BART Evaluations for OG&E have been updated using actual annual baseline emissions rather than the conservatively high baseline emission rate developed for visibility impact modeling. Using the more realistic baseline emissions, the average cost effectiveness of Dry FGD-SDA at the OG&E units ranges from $9,625 to $10,883 per ton of SO_2 removed, and the average cost effectiveness of Wet FGD ranges from $10,271 to $11,490 per ton. The cost effectiveness of FGD control on the OG&E units is poor in comparison to the cost effectiveness estimates used by EPA to establish the presumptive BART emission limits. EPA estimated that most of the BART applicable units could meet the presumptive standards at a cost of $400 to $2,000 per ton of SO_2 removed. The revised cost effectiveness information for the OG&E stations supports a determination that low sulfur coal is BART for OG&E's units.

Sincerely,

Ken Snell, P.E.
Senior Environmental Consultant

Sargent & Lundy

Oklahoma Gas & Electric Company
Sooner and Muskogee Generating Stations
BART Determination – Cost Effectiveness Update
September 16, 2009

Sooner Unit 1
Annual SO_2 Emissions

Control Technology	SO_2 Emissions (lb/mmBtu)	Sooner 1 Emissions (tpy)*	Sooner 1 Reduction in Emissions (tpy)*
Wet FGD	0.08	1,613	7,781
Dry FGD – SDA	0.10	2,017	7,377
Baseline	0.509	9,394	–

* Baseline annual emissions were calculated based on average annual SO_2 emissions for the years 2004-2006. Projected annual emissions were calculated based on the controlled SO_2 emission rate, full load heat input of 5,116 mmBtu/hr, and assuming 7,884 hours/year (90% capacity factor).

Sooner Unit 1
SO_2 Emission Control System Cost Summary

Control Technology	Total Capital Investment* ($)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
Wet FGD	$441,658,000	$37,898,900	$42,017,000	$79,915,900
Dry FGD – SDA	$390,406,000	$33,500,900	$37,505,800	$71,006,700

* Capital costs for SO_2 control systems will be similar for Sooner Units 1 & 2. Capital costs include the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the control system. Capital costs for the Wet FGD scenario include the cost of a new chimney, and capital costs for the Dry FGD scenario include the cost of a post-scrubber fabric filter baghouse.

Sooner Unit 1
SO_2 Emission Control System Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness* ($/ton)
Wet FGD	$79,915,900	7,781	$10,271	$22,052
Dry FGD – SDA	$71,006,700	7,377	$9,625	–

*Incremental cost effectiveness of the wet FGD control systems compared to the SDA control system.

Sargent & Lundy LLC

Oklahoma Gas & Electric Company
Sooner and Muskogee Generating Stations
BART Determination – Cost Effectiveness Update
September 16, 2009

Sooner Unit 2
Annual SO_2 Emissions

Control Technology	SO_2 Emissions (lb/mmBtu)	Sooner 1	
		Emissions (tpy)*	Reduction in Emissions (tpy)*
Wet FGD	0.08	1,613	6,957
Dry FGD – SDA	0.10	2,017	6,553
Baseline	0.516	8,570	--

* Baseline annual emissions were calculated based on average annual SO_2 emissions for the years 2004-2006. Projected annual emissions were calculated based on the controlled SO_2 emission rate, full load heat input of 5,116 mmBtu/hr, and assuming 7,884 hours/year (90% capacity factor).

Sooner Unit 2
SO_2 Emission Control System Cost Summary

Control Technology	Total Capital Investment* ($)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
Wet FGD	$441,658,000	$37,898,900	$42,036,700	$79,935,600
Dry FGD – SDA	$390,406,000	$33,500,900	$37,556,000	$71,056,900

* Capital costs for SO_2 control systems will be similar for Sooner Units 1 & 2. Capital costs include the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the control system. Capital costs for the Wet FGD scenario include the cost of a new chimney, and capital costs for the Dry FGD scenario include the cost of a post-scrubber fabric filter baghouse.

Sooner Unit 2
SO_2 Emission Control System Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness* ($/ton)
Wet FGD	$79,935,600	6,957	$11,490	$21,977
Dry FGD – SDA	$71,056,900	6,553	$10,843	--

*Incremental cost effectiveness of the wet FGD control systems compared to the SDA control system.

55 East Monroe Street • Chicago, IL 60603-5780 • 312-269-2000

Sargent & Lundy LLC

Oklahoma Gas & Electric Company
Sooner and Muskogee Generating Stations
BART Determination – Cost Effectiveness Update
September 16, 2009

Muskogee Unit 4
Annual SO_2 Emissions

Control Technology	SO_2 Emissions (lb/mmBtu)	Sooner 1 Emissions (tpy)*	Sooner 1 Reduction in Emissions (tpy)*
Wet FGD	0.08	1,728	7,385
Dry FGD – SDA	0.10	2,160	6,953
Baseline	0.507	9,113	--

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

Muskogee Unit 4
SO_2 Emission Control System Cost Summary

Control Technology	Total Capital Investment* ($)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
Wet FGD	$418,567,000	$35,917,500	$40,335,100	$76,302,600
Dry FGD – SDA	$373,106,000	$32,016,400	$36,418,000	$68,434,400

* Capital costs for SO_2 control systems will be similar for Muskogee Units 4 & 5. Capital costs include the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the control system. Capital costs for the Wet FGD scenario include the cost of a new chimney, and capital costs for the Dry FGD scenario include the cost of a post-scrubber fabric filter baghouse.

Muskogee Unit 4
SO_2 Emission Control System Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness* ($/ton)
Wet FGD	$76,302,600	7,385	$10,332	$18,213
Dry FGD – SDA	$68,434,400	6,953	$9,842	--

*Incremental cost effectiveness of the wet FGD control systems compared to the SDA control system.

Sargent & Lundy LLC

Oklahoma Gas & Electric Company
Sooner and Muskogee Generating Stations
BART Determination – Cost Effectiveness Update
September 16, 2009

Muskogee Unit 5
Annual SO_2 Emissions

Control Technology	SO_2 Emissions (lb/mmBtu)	Sooner 1 Emissions (tpy)*	Sooner 1 Reduction in Emissions (tpy)*
Wet FGD	0.08	1,728	7,278
Dry FGD – SDA	0.10	2,160	6,846
Baseline	0.514	9,006	--

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

Muskogee Unit 5
SO_2 Emission Control System Cost Summary

Control Technology	Total Capital Investment* ($)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
Wet FGD	$418,567,000	$35,917,500	$40,406,300	$76,323,800
Dry FGD – SDA	$373,106,000	$32,016,400	$36,471,700	$68,488,100

* Capital costs for SO_2 control systems will be similar for Muskogee Units 4 & 5. Capital costs include the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the control system. Capital costs for the Wet FGD scenario include the cost of a new chimney, and capital costs for the Dry FGD scenario include the cost of a post-scrubber fabric filter baghouse.

Muskogee Unit 5
SO_2 Emission Control System Cost Effectiveness

Control Technology	Total Annual Cost ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness* ($/ton)
Wet FGD	$76,323,800	7,278	$10,487	$18,138
Dry FGD – SDA	$68,488,100	6,846	$10,004	--

*Incremental cost effectiveness of the wet FGD control systems compared to the SDA control system.

Exhibit 3

Oklahoma Gas & Electric

OG+E®

Sooner Units 1 & 2, Muskogee Units 4 & 5
Dry FGD BART Analysis Follow-Up Report

Prepared by: Sargent & Lundy LLC
Chicago, Illinois

Sargent & Lundy LLC

December 15, 2009

Table of Contents

1.0 INTRODUCTION

In spring 2008, S&L completed Best Available Retrofit Technology (BART) evaluations for Sooner Units 1 & 2, Muskogee Units 4 & 5, and Seminole Units 1, 2, & 3. The BART evaluations included an analysis of potentially feasible retrofit emission control technologies to control emissions of nitrogen oxide (NO_X), sulfur dioxide (SO_2), and particulate matter (PM_{10}) from each unit. BART evaluations included in the 2008 reports followed the five-step BART determination process described in Appendix Y to 40 CFR Part 51 "Guidelines for BART Determinations under the Regional Haze Rule." The five-step BART determination process includes:

Step 1: Identify all available retrofit control technologies;
Step 2: Eliminate technically infeasible options;
Step 3: Evaluate the control effectiveness of the remaining control options;
Step 4: Evaluate impacts and document the results; and
Step 5: Evaluate visibility impacts.

Step 4 of the process involves an evaluation of the potential environmental, energy, and economic impacts to the facility associated with the installation and operation of the technically feasible retrofit control options. To address economic impacts, S&L prepared a cost estimate for each technically feasible retrofit control option. To the extent possible, cost estimating methodologies described in the Office of Air Quality Planning and Standards Cost Control Manual ("OAQPS Cost Manual") were used to estimate annual costs. Cost estimates were used to evaluate the cost effectiveness of each technology in terms of annual dollars per ton of pollutant removed.

On November 13, 2009, the State of Oklahoma published its draft Regional Haze Implementation Plan Revision ("Regional Haze Implementation Plan"). The draft implementation plan required OG&E to control SO_2 emissions from Sooner Units 1 & 2 and Muskogee Units 3 & 4 with dry flue gas desulfurization (DFGD) control systems as BART. In the draft implementation plan, the Oklahoma Department of Environmental Quality (DEQ) questioned the cost estimates included in OG&E's 2008 BART evaluation, stating "OG&E's estimated costs were found to be substantially higher than those reported for similar projects." DEQ based its BART determination on revised cost estimates, both capital and operating and maintenance (O&M) costs, as well as a revised cost effectiveness evaluation.

Specifically, DEQ questioned the following items in the OG&E DFGD cost estimates:

a) The higher than expected DFGD capital costs when compared to other sources of information and the availability of back up information to support the cost estimates.
b) The high cost effectiveness ($9,625 to $10,843 $/ton) compared to other BART evaluations.
c) What the 2009 capital costs would be considering costs likely peaked in 2008 around the time of the original BART report and have likely fallen since then.
d) The accuracy of using factors from the EPA Air Pollution Control Cost Manual to develop annual operating costs given the large escalation in capital costs over the last few years.

The economic impact analysis included in the 2008 OG&E BART determinations calculated the cost effectiveness of DFGD control technology for Sooner Units 1 & 2 and Muskogee Units 4 & 5 on a dollar per ton of pollutant removed basis. Annual costs were calculated by adding annual operation and maintenance (O&M) costs to the annualized capital cost of a DFGD control system. To the extent possible, methodologies described in the OAQPS Cost Manual were used to estimate capital and O&M costs. Cost effectiveness ($/ton) of a DFGD was calculated by dividing the total annual cost ($/yr) by the reduction in annual emissions (ton/yr).

In addition to comments from DEQ, on December 4, 2009, the U.S. Department of the Interior, U.S. Fish and Wildlife Service (FWS), in consultation with the National Park Service (NPS) submitted comments to DEQ regarding the draft Regional Haze Implementation Plan. FWS/NPS agreed with DEQ that costs presented by OG&E for SO_2 control were excessive. To respond to DEQ and FWS/NPS questions and concerns, S&L prepared the following:

a) <u>Updated 2009 Conceptual Capital Cost Estimates</u>
The original 2008 BART report capital cost estimates were study type +/-30% estimates based primarily on conceptual cost estimates prepared for similar projects that were scaled to account for major differences. The 2009 conceptual capital cost estimate (included herein) for Sooner Units 1 & 2 is based on project-specific vendor quotations for certain major equipment items and inputs developed by performing preliminary project engineering. The 2009 conceptual capital cost estimate is in the +/-20% accuracy range. A comparison of the revised capital cost estimate against the sources cited by DEQ in the draft Regional Haze Implementation Plan is also included. The Muskogee Unit 4 & 5 capital cost estimate is still being developed, and will be submitted to DEQ within the next week. Due to similarities in the unit sizing, plant layouts, geographical location, and fuel sources, the base Muskogee estimate will be very similar to the Sooner estimate. The draft schedule included in Attachment A, assumes the Muskogee work will take place after the Sooner work; therefore, the Muskogee cost estimate will have additional escalation costs included.

b) Operating Cost Estimates

Operating costs included in the original 2008 BART report were primarily based on default factors taken from the OAQPS Cost Manual and U.S.EPA's Coal Utility Environmental Cost (CUECost) model. Updated operating costs included in this report were developed by S&L using OG&E supplied tax, wage, financial, and insurance information, as well as industry standards and vendor quotations.

c) Updated Cost Effectiveness Estimates

The updated conceptual capital cost and operating cost estimates were used to calculate revised cost effectiveness estimates.

d) Alternative Methods for Calculating Reductions in Annual Emissions and Visibility Impacts

FWS/NPS also questioned the methodology used by OG&E to calculate the amount of pollutant removed with DFGD controls. The amount of pollutant removed (tons/year) has a direct effect on the cost effectiveness of the pollution control system. To address the FWS/NPS comments, emission reductions from each of the OG&E units were calculated based on using two different baseline emission rates and three different post DFGD emission rates. This was done to show the effect on the cost effectiveness calculations, and to "envelope" the cost effectiveness calculations. Cost effectiveness in terms of modeled visibility improvements at affected Class I Areas ($/dV) were also revised to reflect the updated cost estimates.

e) Comparison against BART submittals from similar projects

Results of the OG&E BART cost effectiveness impacts ($/ton and $/dV) are compared against impacts reported in other BART evaluations.

2.0 2009 COST ESTIMATES AND COST EFFECTIVNESS UPDATE

2.1 2009 CONCEPTUAL CAPITAL COST ESTIMATE

The 2009 conceptual capital cost estimate and supporting information for Sooner Units 1 and 2 are included in Attachment A. Muskogee capital conceptual capital cost estimates will be completed at a later date but are expected to be very close to the Sooner costs except for the escalation values. Table 1 provides a summary of the Sooner Station 2009 conceptual capital cost estimate with the costs divided evenly between Units 1 and 2.

Table 1
Sooner Unit 1 or Unit 2
2009 Capital Cost Estimate

Item	2009 Cost Estimate
Direct Costs	$162,651,000
Indirect Costs	$24,045,000
Escalation	$23,301,000
Sales Tax	$0
Contingency	$29,337,000
AFUDC & Bond Costs	$52,960,000
TOTAL CAPITAL COST	**$292,294,000**
Cost Per kw (gross)	$514

The conceptual cost estimate provided in Attachment A takes into account the retrofit difficulty that can be expected from the existing Sooner site configuration. In degree of difficulty, the retrofit at Sooner could be described as average. The new DFGD locations are relatively clear but Unit 1 is tightly bounded on the east side by two coal conveyors that supply both units and on the west by high voltage duct-bank, ash piping, and circulating water piping. This existing equipment creates a narrow construction corridor for installing the DFGD equipment. As a result, the DFGD has a long narrow configuration with relatively long ductwork runs. There is also some ash piping and supports near the existing chimney and ID fans that would have to be relocated to accommodate the new ductwork. The existing storm sewer system in the new DFGD area would have to be completely removed and reinstalled to accommodate the new equipment foundations. A main east-west underground piping run also goes through the new DFGD area and would have to be relocated. All of the site-specific retrofit challenges, including equipment relocations, have been taken into consideration in the conceptual cost estimate.

2.2 METHODOLOGY FOR DEVELOPING THE CONCEPTUAL COST ESTIMATE

S&L developed the 2009 Sooner capital cost estimates using the following methodology:

- Sooner plant design data was 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. Costs obtained from these quotations were used to derive the pricing used in the capital cost estimate. The cost development for the spray dryer absorbers and baghouse used in the estimate is described in Attachment A.
- 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, relocations, 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 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 a 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 Oklahoma area wage rates, installation quantities, and installation rates taken from the S&L database.

This 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 and Muskogee Stations.

2.3 COMPARISON BETWEEN 2008 AND 2009 COST ESTIMATES

A comparison of the 2008 and 2009 cost estimates for Sooner Units 1 & 2 is provided in Table 2.

Table 2
Sooner Unit 1 or Unit 2
2008 and 2009 Capital Cost Estimate Comparison(1)

Item	2008 Cost Estimate	2009 Cost Estimate
Total Costs ($)	$390,406,000	$292,294,000
Cost per kw ($/kw)	$686	$514
Cost Difference (%)	Base	-25%
Contingency ($)	$56,598,000	$29,337,000

(1) The Total Project Cost for DFGD on both units at the Sooner Station is estimated to be $584,589,800. Costs summarized in this table are divided equally between the two units.

Major factors contributing to the reduction of costs from 2008 to 2009 include:

a) Direct Costs
The 2008 estimate was prepared when the demand for DFGD systems was high and costs were near their peak. It is estimated that major equipment costs have dropped approximately 15% to 20% since this time.

b) Contingency Costs
The 2009 estimate was based on vendor quotations for major equipment and preliminary engineering to develop quantities. As a result of this additional cost certainty, the contingency factor in the 2009 estimate (14%) is approximately 6% lower than the 2008 estimate. The difference in contingency amounts between the two estimates is illustrated in Table 2-2.

c) Escalation Costs
The estimate of future escalation is lower in 2009 than it was in early 2008 when prices had been rapidly increasing over the previous three years. The difference in overall project escalation factors is about 10%.

The cumulative effect of changes in the above three cost items, with all other things being equal, would be about a 20% to 30% reduction in pricing from 2008 to 2009. The actual decrease was about 25% which falls into this range. We believe this validates the capital costs provided in the 2008 estimate.

2.4 UPDATED TOTAL ANNUAL COSTS AND COST EFFECTIVENESS

In general, total annual costs are the sum of the capital recovery costs and annual O&M costs. Cost effectiveness of a pollution control system is calculated by dividing the total annual cost of the control system ($/year) by the total annual quantity of pollutant removed by the system (tons/year); where:

- Annual Cost (Reference Year $/year) = Annualized Capital Costs + Annual Operating Costs;

- Annualized Capital Costs (Reference Year $/year) = Total Capital Requirement x Capital Recovery Factor;

- Total Capital Requirement (Reference Year $) = All capitalized expenses as of the commercial operating date, including direct costs, indirect costs, and allowance for funds used during construction (AFUDC);

- Capital Recovery Factor = The factor that converts the Total Capital Requirement into equal annual costs over the depreciable life of the asset, accounting for OG&E returns on debt and equity and income taxes, expressed in real terms (i.e., inflation removed); and

- Annual Operating Costs (Reference Year $/year) = Variable O&M Costs + Fixed O&M Costs + Indirect Operating Costs.

The following sections describe the derivation of these components of the cost estimate.

2.4.1 Capital Costs

Conceptual capital costs for the DFGD control projects at each OG&E station were calculated using the methodology described in Section 2.2. The total capital requirement (TCR) is the sum of direct costs, indirect costs, contingency, escalation, and allowance for funds used during construction. 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 TCR for each unit is summarized in Tables B-1 through B-4 in Attachment B.

Capital Recovery Factor

The capital recovery factor converts the TCR into equal annual costs over the depreciable life of the asset, accounting for OG&E returns on debt and equity and income taxes, expressed in real terms (i.e., inflation removed). These are also referred to as levelized capital charges. Property taxes and insurance are sometimes included with the capital charges, but are classified in this 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 3.

Table 3
Economic Parameters to Derive Levelized Capital Charges

Commercial Operation Date (Reference Year)	
Sooner	2014
Muskogee	2015
Depreciable Life	20 years
Inflation Rate	2.50%/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

Based upon the above parameters, the real levelized capital charge rate (capital recovery factor) is 10.36%/year. The derivation of this value is shown in Table B-5 in Attachment B. The TCR multiplied by 10.36% thus determines the Annualized Capital Costs.

2.4.2 Operating Costs

Annual operating costs for the DFGD system consist of variable O&M costs, fixed O&M costs, and indirect operating costs. The derivation of each cost component is described below.

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, which were derived as follows:

- Lime Reagent. Based on material balances for the average fuel composition and 90% capacity factor. The first-year delivered cost of lime is $118.80/ton for Sooner and $105.53/ton for Muskogee based on budgetary lime quotations received for truck delivery.

- Water. Based on 205,256 lb/hr at full load at Sooner, 219,839 lb/hr at full load at Muskogee, and 90% capacity factor. The first-year cost of water is $0.49/1000 gallons at Sooner and $2.57/1000 gallons at Muskogee. Water unit costs are based on information received from OG&E. The Muskogee water cost includes the cost of purchasing water. Sooner does not have any water purchase costs.

- FGD Waste Disposal. Based on material balances for the average fuel composition and 90% capacity factor. The first year cost of on-site disposal is $39.60/ton at Sooner and $40.59/ton at Muskogee. Disposal cost only includes FGD by-products and does not include fly ash.

- Bag and Cage Replacement. Based on the exhaust gas flow through the baghouse, 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 at Sooner and $3.31/ft^2 at Muskogee.

- Ash Disposal. Assumed no increase in ash disposal with the fabric filter due to the existing ESP remaining in service.

- Auxiliary Power Cost. Based on auxiliary power calculations and 90% capacity factor. The first year auxiliary power cost is $83.83/MWh at Sooner and $85.92/MWh at Muskogee.

Fixed O&M

Fixed O&M costs are recurring annual costs that are generally independent of the plant capacity factor. These consist of operating labor, supervisor labor, maintenance materials, and maintenance labor, which were derived as follows:

- Operating Labor. Based on three shifts/day 365 days/year. The first year labor rate (salary plus benefits) is $57.33/hour at Sooner and $58.76/hour at Muskogee.

- Supervisory Labor. This was based on 15% of operating labor, according to the EPA Control Cost Manual, page 2-31. S&L determined that the EPA approach provides a reasonable estimate for this cost item.

- Maintenance Materials. This was based on 0.6% of the total plant investment, based on Sargent & Lundy's experience on other FGD projects.

- Maintenance Labor. This was based on 110% of operating labor, according to the EPA Control Cost Manual, page 2-31. S&L determined that the EPA approach provides a reasonable estimate for this cost item.

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, which were derived as follows:

- Property Taxes. Calculated as 0.60 % of total capital investment at Sooner and 0.85% of total capital investment at Muskogee, according to OG&E property tax rates. These rates are significantly lower than those used in the EPA Air Pollution Control Cost Manual 6th Ed., page 2-34.

- Insurance. Calculated as 0.0105 % of total capital investment at both Sooner and Muskogee, according to OG&E insurance rates. These rates are significantly lower than those used in the EPA Air Pollution Control Cost Manual 6th Ed., page 2-34.

- Administration. These are calculated as 20% of the fixed O&M based on Sargent & Lundy's experience on other projects. This results in significantly lower costs compared to those obtained using the methodology described in the EPA Air Pollution Control Cost Manual 6th Ed., page 2-34.

Total Annual Operating Costs

The total annual operating costs for each unit are calculated in Tables B-1 through B-4 in Attachment B and are approximately $29 to $32/kw per year. These costs compare favorably with industry O&M data for existing coal plants, and are within the normal range of expected O&M costs for dry FGD systems. The annual operating cost of approximately $29 to $32/kw is significantly lower than the $68/kw calculated in the 2008 BART report which was derived using OAQPS Cost Manual and CUECost default factors, and is lower than the $43 to $47/kw estimated by the DEQ in the draft Regional Haze Implementation Plan.

2.4.3 2009 Cost Effectiveness

Total annual DFGD costs for each unit are summarized in Table 4. Detailed cost calculations are shown in Tables B-1 through B-4 in Attachment B. Total annual costs are divided by the annual tons of SO_2 removed to calculate average control technology cost effectiveness. Annual emission reductions associated with DFGD control systems are summarized in Table 5 using the same basis as the September 2009 OG&E BART update. The SO_2 control efficiency for each unit is summarized in Table 6

Table 4
DFGD Total Annual Cost Summary

Unit	Capital Recovery ($/year)	Annual O&M ($/year)	Total Annual Cost ($/year)
Muskogee 4	$31,854,600	$18,285,500	$50,140,100
Muskogee 5	$31,854,600	$18,285,500	$50,140,100
Sooner 1	$30,281,800	$16,550,500	$46,832,300
Sooner 2	$30,281,800	$16,550,500	$46,832,300

Table 5
BART Annual SO2 Emission Reductions with Dry FGD

Unit	Baseline Annual SO2 Emissions (1) (tpy)	Projected Post-Control Annual Emissions (2) (tpy)	Annual Emission Reductions (tpy)
Muskogee 4	9,113	2,160	6,953
Muskogee 5	9,006	2,160	6,846
Sooner 1	9,394	2,017	7,377
Sooner 2	8,570	2,017	6,553

(1) In this table baseline SO_2 emissions are calculated as the average actual SO_2 emission rate during the baseline years of 2004 – 2006.

(2) In this table projected post-control SO_2 emissions are calculated based on a controlled SO_2 emission rate of 0.10 lb/mmBtu and a 90% capacity factor.

Table 6
Average Cost Effectiveness

Unit	Annual Cost ($/year)	SO_2 Removed (tons/year)	Average Cost Effectiveness ($/ton)
Muskogee 4	$50,140,100	6,953	$7,211
Muskogee 5	$50,140,100	6,846	$7,324
Sooner 1	$46,832,300	7,377	$6,348
Sooner 2	$46,832,300	6,553	$7,147

Cost effectiveness is a function of both the cost of a control system and the annual tons of pollutant removed. With respect to tons removed, various bases can be used to calculate both the baseline emission rate and the post-project controlled emission rate. Varying either the baseline calculation or the projected emissions calculation will result in a different cost effectiveness value.

To account for this variability, the cost effectiveness of DFGD controls at Sooner and Muskogee were calculated using various baseline and projected SO_2 emission rates. Emission rates were chosen to “envelope” the cost effectiveness of the DFGD control systems. For example, baseline SO_2 emissions were based on the actual average SO_2 emission rate during the 2004-2006 baseline period, as well as the highest annual SO_2 emissions during the baseline period. Projected SO_2 emissions were calculated using the presumptive SO_2 emission rate of 0.15 lb/mmBtu, as well controlled SO_2 emission rates of 0.10 and 0.08 lb/mmBtu. Finally, capacity factors of either 90% (which is more representative of actual operations) or 100% (which represents potential emissions but would not represent actual operations) were also used.

Although annual O&M costs will vary depending on the controlled SO_2 emission rate (i.e., lower post-project SO_2 emission rates will have a higher annual variable O&M cost), for this analysis total annual costs were held constant. Cost effectiveness calculations for two alternative scenarios are summarized in Tables 5a & 6a and 5b & 6b.

Table 5a
BART Annual SO2 Emission Reductions with Dry FGD
(Scenario 2)

Unit	Baseline Annual SO2 Emissions (1) (tpy)	Projected Post-Control Annual Emissions (2) (tpy)	Annual Emission Reductions (tpy)
Muskogee 4	9,775	3,600	6,175
Muskogee 5	10,224	3,600	6,624
Sooner 1	10,189	3,361	6,828
Sooner 2	8,746	3,361	5,385

(1) In this table baseline SO_2 emissions reflect the highest annual SO_2 emission rate during the baseline years of 2004 – 2006.
(2) In this table projected post-control SO_2 emissions are calculated based on a controlled SO_2 emission rate of 0.15 lb/mmBtu (the presumptive BART emission rate) and a 100% capacity factor.

Table 6a
Average Cost Effectiveness
(Scenario 2)

Unit	Annual Cost ($/year)	SO_2 Removed (tons/year)	Average Cost Effectiveness ($/ton)
Muskogee 4	$50,140,100	6,175	$8,120
Muskogee 5	$50,140,100	6,624	$7,569
Sooner 1	$46,832,300	6,828	$6,859
Sooner 2	$46,832,300	5,385	$8,697

Table 5b
BART Annual SO2 Emission Reductions with Dry FGD
(Scenario 3)

Unit	Baseline Annual SO2 Emissions (1) (tpy)	Projected Post-Control Annual Emissions (2) (tpy)	Annual Emission Reductions (tpy)
Muskogee 4	9,775	1,920	7,855
Muskogee 5	10,224	1,920	8,304
Sooner 1	10,189	1,793	8,396
Sooner 2	8,746	1,793	6,953

(1) In this table baseline SO_2 emissions reflect the highest annual SO_2 emission rate during the baseline years of 2004 – 2006.
(2) In this table projected post-control SO_2 emissions are calculated based on a controlled SO_2 emission rate of 0.08 lb/mmBtu and a 100% capacity factor. A controlled SO_2 emission rate of 0.08 lb/mmBtu represents the lowest SO_2 emission rate that could reasonably be expected to be achieved on a large subbituminous coal-fired unit with a retrofit DFGD control system.

Table 6b
Average Cost Effectiveness
(Scenario 3)

Unit	Annual Cost ($/year)	SO_2 Removed (tons/year)	Average Cost Effectiveness ($/ton)
Muskogee 4	$50,140,100	7,855	$6,383
Muskogee 5	$50,140,100	8,304	$6,038
Sooner 1	$46,832,300	8,396	$5,578
Sooner 2	$46,832,300	6,953	$6,736

Cost effectiveness varies depending on the baseline and controlled SO_2 emission rates used in the evaluation. Under all scenarios, DFGD cost effectiveness on the OG&E units is greater than $5,550/ton. Based on the BART presumptive level of 0.15 lb/mmBtu, and assuming a 100% capacity factor, cost effectiveness of DFGD on the Muskogee and Sooner units would be in the range of $6,859 to $8,697/ton (see, Table 6a). Cost effective values calculated using the BART presumptive level should be used to compare cost effective at other BART applicable sources.

In addition to calculating cost effectiveness on a $/ton basis, with respect to regional haze impacts, cost effectiveness can be calculated as a function of annual costs and modeled visibility improvements at the affected Class I Areas. Modeled visibility improvements will be a function of the proximity of the unit to the Class I Area, baseline and controlled emissions, and the pollutant being controlled. Table 7 provides a summary of the modeled reduction in visibility impairment (measured in deciview- dv) resulting from DFGD controls on the Muskogee and Sooner generating units. The cost effectiveness of DFGD controls as a function of modeled reductions in visibility impairment (using two different impact criteria) is provided in Tables 8 and 8a.

Table 7
Modeled Visibility Improvement at the Class I Areas (dv)

Class I Area	Muskogee Units 4 & 5	Sooner Units 1 & 2
Wichita Mountains National Wildlife Refuge	1.275	0.51
Caney Creek Wilderness Area	0.804	0.32
Upper Buffalo Wilderness Area	1.11	0.44
Hercules-Glades Wilderness Area	1.028	1.17
Total	**4.217**	**2.44**

Table 8
Average Cost Effectiveness ($/dv)

Unit	Annual Cost ($/year)	Modeled Visibility Improvement(1) (dv)	Average Cost Effectiveness ($/dv)
Muskogee 4 & 5	$100,280,200	1.275	$78,651,137
Sooner 1 & 2	$93,664,600	1.17	$80,055,214

(1) The modeled reduction in visibility impairment used in this table represents the highest single modeled reduction at a single Class I Area.

Table 8a
Average Cost Effectiveness ($/dv)

Unit	Annual Cost ($/year)	Modeled Visibility Improvement(1) (dv)	Average Cost Effectiveness ($/dv)
Muskogee 4 & 5	$100,280,200	4.217	$23,779,986
Sooner 1 & 2	$93,664,600	2.44	$38,387,131

(1) The modeled reduction in visibility impairment used in this table represents the cumulative reduction of all Class I Areas.

Based on the cost effectiveness calculations summarized above, taking into considered modeled visibility improvements at all of the affected Class I areas, the cost effectiveness of DFGD on Sooner Units 1 & 2 will be in the range of $38,387,000/dv, and the cost effectiveness of DFGD on Muskogee Units 4 & 5 will be in the range of $23,780,000/dv.

2.5 COMPARISON OF 2009 CAPITAL COSTS AGAINST OTHER PUBLISHED CAPITAL COST INFORMATION

Appendix 6-4 of the November 13, 2009 Oklahoma draft Regional Haze Implementation Plan Revision includes DEQ's BART analysis for each OG&E BART applicable unit. In each of the OG&E BART determinations, DEQ revised the cost estimates for retrofit DFGD control systems, including revisions to the capital costs and annual O&M costs. Although DEQ stated that, in general, the cost estimating methodology used by OG&E "followed guidance provided in the EPA Air Pollution Cost Control Manual," DEQ concluded, based on a review of other BART submittals, that OG&E's costs were substantially higher than those reported for similar projects. (Draft Regional Haze Implementation Plan, Appendix 6-4, page cliii). DEQ proceeded to revise the capital costs and O&M costs based on cost information provided in the following publications: (1) a Colorado Department of Public Health and Environment report titled "Summary of Research and Potential Control Options, Emission Reductions and Costs for Reducing SO2 and NOx from Existing Major Colorado Point Sources"; (2) a March 1, 2009 article in Power, on online industry magazine, titled "Update: What's That Scrubber Going to Cost" written by George W. Sharp of American Electric Power; and (3) a report prepared by Sargent & Lundy for the National Lime Association titled "Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD" dated March 2007.

In its comments to DEQ regarding the draft Regional Haze Implementation Plan FWS/NPS agreed with DEQ that costs presented by OG&E for SO2 control were excessive. In addition, FWS/NPS provided an alternative lower cost analysis using capital costs "taken from the 2007 Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD, prepared for National Lime Association."

We address each of the referenced documents below.

2.5.1 Colorado Department of Public Health and Environment Report

The Colorado Department of Public Health and Environment report included unit capital costs for retrofit dry scrubbers on 500 MW units burning PRB coal. The report was prepared by BBC Research and Consulting, and relied on cost data in a 2003 report prepared by Sargentt & Lundy titled "Economics of Lime and Limestone for Control of Sulfur Dioxide" (the 2003 National Lime Report). As discussed in more detail below, capital costs included in the 2003 National Lime Report were intended to provide a comparison between lime-based and limestone-based scrubbing technologies, and were not intended to be used as the basis for a project-specific capital cost estimate.

2.5.2 2007 National Lime Association Report

Both DEQ and FWS reference the 2007 National Lime Report prepared by Sargent & Lundy as a basis for their capital cost revisions. In fact, the FWS's alternative capital costs were based on numbers provided in the 2007 National Lime Report. However, the National Lime report was only intended to provide a comparative cost effectiveness evaluation of wet limestone-based FGD control systems and dry lime-based control systems. The report was not intended to provide an evaluation of total capital requirements for either type of control technology and was not intended to serve as the basis for a capital cost estimate. The 2007 report clearly states:[1]

> FGD prices have seen a minimum of 25% inflation in the past year. Some recent contracts have been signed at prices over 300% higher than the market of 5 years ago. The costs [in this report] have been prepared on a consistent, uniform basis and show a level that some buyers achieved in mid-2006. Sargent & Lundy cautions the reader that the costs provided herein are not indicative of any cost you may actually achieve. However, we believe the costs are valid for comparative purposes. These costs should *not* be used for any of these purposes;
>
> - Planning the cost of a FGD project
> - Budget requests or allocations
> - Solicitation of pollution control bonds
>
> In today's market place, it is impossible to determine capital cost of an FGD system until the contract is signed with the supplier.

Capital costs in both the 2003 and 2007 National Lime Reports were developed for comparative purposes only. Furthermore, costs in the 2007 report were based on 2006 dollars and did not include escalation, which can add approximately 10% to 20% to the project cost. Nor do the reports take into consideration any site-specific retrofit challenges. Capital costs in the National Lime Reports were presented on a consistent basis for comparative purposes only. Cost estimates using the methodology described in Section 2.1 of this report provide a more accurate accounting of actual costs that will be incurred by OG&E to install and operate dry FGD control systems at Sooner and Muskogee

[1] See, Sargent & Lundy, "Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD," prepared for the National Lime Association, March 2007, page 2 (emphasis in the original).

2.5.3 "Update: What's That Scrubber Going to Cost" article

DEQ also used capital cost estimates summarized in a March 1, 2009 article in "Power" an online industry magazine to adjust the capital costs for DFGD retrofit projects at the OG&E stations. The Power article provided a survey of FGD projects at large electric utility generating stations during the period of December 2007 through June 2008. The article summarized the average total installed costs of FGD control systems as reported by the survey respondents, noting that the reported costs "were expected to have wide variation, principally because of the peculiarities that exist at each project site, the retrofit project complexity, and the timing differences between projects." Therefore, assigning a project-specific cost based on information summarized in the article would not be correct without taking into consideration project specific details.

Furthermore, the 2009 OG&E conceptual capital cost of $514/kw is reasonably close to the $359 to $471/kw taken from this article. The article reported that the 2008 cost surveys were 28% higher than those reported in the 2007 survey with an average of $359/kw for 600 to 900 MW plant range and $471/kw for 300 to 599 MW range. Note that these values are averages and include units with wide ranges of in service dates. In fact, 55% of the units in the survey were expected to be in operation by 2009 whereas the OG&E units are not expected to be in operation until 2014 and 2015. The 55% of the units in operation by 2009 would have had their major equipment purchased prior to the 28% run up in pricing in 2008 from late 2006 and prior to the 22% run up in pricing from 2006 to 2007 referenced in the same article. The OG&E units would be subject to these escalated costs and future escalation.

In addition, the OG&E units would also require a higher level of contingency since the projects are still in the early study phase. As a result, units going into service in the near future would be expected to be below the average cost while units going into service at later dates would be expected to be above the average cost. The article only provides an average cost and does not provide any information on the cost distribution about the average. A wide distribution is expected as indicated at the bottom of page 65 where it states that "average total installed costs reported by the survey respondents were expected to have wide variation" based partially on the "timing differences between projects." Because of the expected wide variation in project costs, this report can be used to illustrate recent industry cost trends but should not be used to estimate the cost of specific units that will not go into service for another 5 to 7 years. Again, it is believed that the methodology described in Section 2.1 will provide more accurate results for a specific project than the cited article.

3.0 BART Report Comparisons

The cost effectiveness of a pollution control system is a function of the total annual cost of the system (taking into consideration capital recovery and annual O&M) and the amount of pollutant removed by the control system (tons per year). With respect to regional haze impacts, cost effectiveness can also be measured as a function of total annual costs divided by the modeled improvement in visibility at the nearby Class I Areas. This measure of cost effectiveness is reported in total annual dollars per deciview change in visibility impairment ($/dv). Thus, in addition to costs, two site-specific factors that impact cost effectiveness are the quantity of pollutant removed and the reduction in modeled visibility impairment.

3.1 COMPARISON OF BASELINE SO_2 EMISSIONS

Table 9 provides a summary of the baseline SO_2 emission rates included in several BART evaluations. A more detailed comparison of some of the costs and cost effectiveness calculations included in various BART determinations is included in Attachment C.

Table 9
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

Of the units listed in Table 9, the OG&E units have the lowest baseline SO_2 emission rates, and among the lowest baseline annual SO_2 emissions (tpy). Baseline emissions have a direct effect on the cost effectiveness of a pollution control system, as shown below:

Cost Effectiveness = Total Annual Costs / (Baseline Emissions – Projected Emissions)

Assuming total annual costs and projected emissions are similar, cost effectiveness will be a function of the baseline emissions. This holds true for units firing subbituminous coals with baseline SO_2 emission 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.[2] DFGD control systems will be more cost effective on units with higher baseline SO_2 emissions because the control system 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. The difference in baseline SO_2 emissions summarized above accounts for some of the variability seen in the BART cost effectiveness calculations. On the basis of the baseline emission rates 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 in Table 9.

3.2 COMPARISON OF MODELED VISIBILITY IMPROVEMENT

Finally, with respect to regional haze impacts, cost effectiveness can also be calculated as a function of modeled improvements in visibility at the Class I areas. This cost effectiveness measurement can be presented by dividing the total annual costs by the degree of visibility improvement at an individual Class I area, or by dividing total annual costs by the sum of visibility improvement across all affected Class I areas. Using either approach, control technologies installed on units with higher baseline emissions and located nearer a Class I area will be more cost effective.

In its comments to DEQ, FWS/NPS argued that cost effectiveness should "consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of

[2] Removal efficiencies achievable with DFGD will be a function of several unit-specific process parameters. Process parameters affecting removal efficiency include: inlet and outlet flue gas temperatures; reactant stoichiometric ratio; how close the DFGD is operated to saturation conditions; the amount of solids product recycled to the atomizer, and the inlet SO_2 concentration. Chemical and physical limitations including flue gas temperature, Ca/S stoichiometry, approach to saturation, mixing and reaction time limit the control efficiency of the DFGD control systems.

improving visibility across all of the Class I areas affected."[3] FWS/NPS reasoned that "[i]t is not appropriate to use the same metric to evaluate the effects of reducing emission from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas."[4] Taking the cumulative impact approach, cost effectiveness will also be a function of the number of Class I areas affected by an individual BART applicable unit. Controls would be more cost-effective on units in near proximity to a Class I area, as well as units located within 300 km of a number of Class I areas. Figure 1 shows the location of the Class I areas in the U.S.

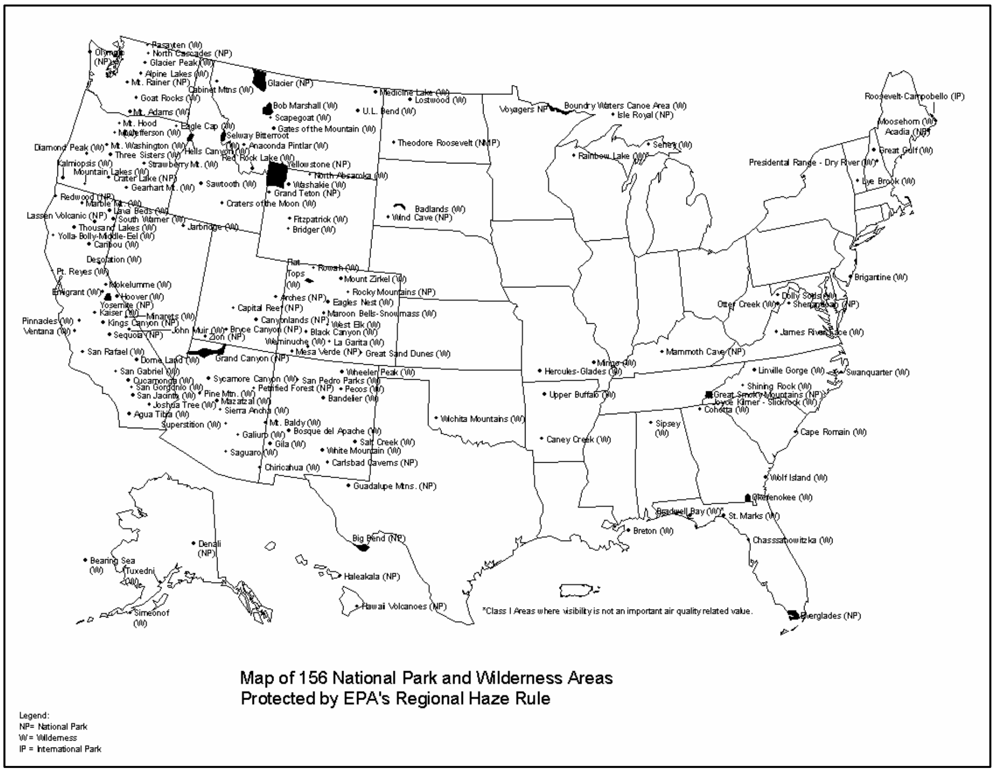


Figure 1
Class I Areas

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 north central Oregon approximately 150 miles east of Portland, is located within 300 km of 14 Class I areas. By comparison, the Sooner and Muskogee stations are located within 300 km of one and four Class I areas, respectively.

[3] FWS/NPS Comments, page 3.
[4] *Id.*

Taking the cumulative impact approach, control technologies will be more cost effectiveness on units affecting a number of Class I areas. For example, modeled visibility improvement at each Class I areas affected by the Sooner, Muskogee, and Boardman stations are summarized in Table 10. Assuming the cost of retrofit controls are similar at all three stations, and assuming that each station achieves similar emission reductions, DFGD controls would be more cost effective at the Boardman Station (on a $/dv basis) simply due to the cumulative improvement in visibility improvement.

Table 10
Comparison of Baseline SO_2 Emissions at Several BART Units

	Muskogee Units 4 & 5	Sooner Units 1 & 2	Boardman Unit 1
1	1.275	0.51	0.777
2	0.804	0.32	0.439
3	1.11	0.44	0.802
4	1.028	1.17	0.544
5	na	na	0.774
6	na	na	0.655
7	na	na	0.659
8	na	na	0.969
9	na	na	0.924
10	na	na	0.614
11	na	na	0.776
12	na	na	0.354
13	na	na	0.681
14	na	na	0.874
Total	**4.217**	**2.44**	**9.842**

In its BART analysis submitted to the Oregon Department of Environmental Quality, total capital requirements and total annual costs for DFGD were estimated at $247,293,000 and $36,322,000, respectively. 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 (e.g., $36,322,000 divided by 9.842 dv). By comparison, because the OG&E stations are located relatively far from a limited number of Class I areas, cost effectiveness at the Sooner and Muskogee stations would be $38,387,000/dV and $23,780,000/dv, respectively.[5]

[5] Sooner = $93,664,600 ÷ 2.44 dv = $38,387,000/dv
Muskogee = $100,280,200 ÷ 4.217 dv = $23,780,000/dv

4.0 Conclusions

Sargent & Lundy updated the retrofit DFGD control system cost estimates for the Sooner and Muskogee Generating Stations. The 2009 conceptual cost estimate (included in this report) was based on project-specific vendor quotations for certain major equipment items and inputs developed by performing preliminary project engineering. The 2009 conceptual capital cost estimate is in the ±20% accuracy range. Total annual costs associated with the installation of DFGD, including capital recovery costs and annual O&M costs were also updated. Annual O&M costs were derived from preliminary engineering mass balance calculations and project-specific unit costs. The cost estimating methodology used herein to develop both capital and O&M costs provides a more accurate estimate of actual costs that OG&E would incur with the installation and operation of DFGD on the Sooner and Muskogee units.

The 2009 conceptual capital cost estimate and supporting information for Sooner Units 1 & 2 are included in Attachment A. Detailed total annual cost summaries, including capital recovery, variable O&M, and fixed O&M calculations are included in Attachment B. Based on the cost estimates, the total capital requirements for DFGD controls on all four OG&E units will be in the range of $1.17 billion dollars. Total annual operating costs will be in the range of $93.6 million/year at Sooner and $100.3 million/year at Muskogee.

Cost effectiveness of a pollution control system is a function of the total annual cost of the system and the quantity of pollutant removed (tons/year). Because of the relatively low baseline SO_2 emission rates at both Muskogee and Sooner (see, Table 9), DFGD will be less cost effective on these units than on similarly sized units with higher baseline SO_2 emissions. Based on expected reductions in actual annual SO_2 emissions, the cost effectiveness of DFGD on the OG&E units will be in the range of $6,348 to $7,324/ton (see, Table 6).

In addition to calculating cost effectiveness on a $/ton basis, with respect to regional haze impacts, cost effectiveness can be calculated as a function of annual costs and modeled visibility improvements at the affected Class I Areas. Modeled visibility improvements will be a function of the proximity of the unit to the Class I Area, baseline and controlled emissions, and the pollutant being controlled. Because the OG&E stations are located relatively far from a limited number of Class I areas, DFGD will be less cost effective (on a $/dv basis) on the OG&E units than on similarly sized units located closer to a Class I area or within 300 km of several Class I areas. Based on modeled visibility improvements, the cost effectiveness at the Sooner and Muskogee stations would be $38,387,000/dV and $23,780,000/dv, respectively.

Attachment A

Sooner Units 1 & 2
Conceptual Cost Estimate

DFGD System
Cost Estimate Account Summary

Account Description	Cost
Dry FGD System	$86,859,600
Fabric Filter	$46,335,000
Ash Recycling System - DFGD Contractor's Scope	$12,072,500
Waste Ash and Fly Ash Handling System	$14,265,600
Flue Gas System	$42,463,000
Mechanical - Balance of Plant	$6,891,300
Electrical - Auxiliary Power and Balance of Plant Electrical Work	$41,935,100
Controls & Instrumentation	$5,088,500
Civil Work	$3,597,400
Removal and Relocation of Existing Equipment and Infrastructure	$2,047,600
Other Costs	$63,746,900
Total Indirect Costs	$48,090,100
Escalation	$46,602,900
Contingency	$58,673,400
Bond Cost	$4,786,700
Interest During Construction (AFUDC)	$101,133,800
Total Project Cost	**$584,589,400**

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
	Dry FGD System							46,462,100	8,209,500				508,270			32,188,000	86,859,600
31-45-25	Dry FGD System		Q	2	LT	15,917,133	0.00	31,834,300	0		136,400	272,800	313,720	MECH	61.53	19,303,200	51,137,500
31-45-35	**Reagent Handling / Preparation**		Est					0	0								0
31-45-35	Reagent Handling / Preparation - Mechanical		Q	2	LT	3,969,614	0.00	7,939,200	0		33600	67,200	77,280	MECH	61.53	4,755,000	12,694,200
26-13-99	Lime Storage Silo with piping for pneumatic unloading (truck)	Concrete Silo - Subcontract price	Q	1	LT	3,200,000	0.00	3,200,000	0		0	0	0	MECH	61.53	0	3,200,000
24-17-15	Elevator for lime silo	four person rack and pinion maintenance elevator - subcontract price includes labor	Est	1	LT	290,000	0.00	290,000	0		0	0	0	MECH	61.53	0	290,000
22-13-27	Concrete pit for the elevator		Est	10	CY	0	210.00	0	2,100		7.5	75	86	CONP	51.69	4,500	6,600
41-99-99	Electrical work for the elevator	allowance	Est	1	LT	0	20,000.00	0	20,000		175	175	201	WIRE	66.93	13,500	33,500
33-43-15	Pneumatic lime transfer equipment/piping	including blowers, piping, and valves	Q	1	EA	400,000	0.00	400,000	0		3500	3,500	4,025	MECH	61.53	247,700	647,700
23-17-23	Access Gallery		Est	2,000	SF	0.00	35.00	0	70,000		0.40	800	920	GALL	67.14	61,800	131,800
																	0
	Dry FGD System - Civil / Structural Work																0
	Foundations for SDA's	Quantities are total for 2 units															
21-23-15	Excavation		Est	2,140	CY	0.00	0.00	0	0		0.20	428	492	EXFD	63.95	31,500	31,500
21-17-25	Backfill		Est	140	CY	0.00	0.00	0	0		0.30	42	48	EXFD	63.95	3,100	3,100
22-13-37	Concrete		Est	2,000	CY	0.00	105.00	0	210,000		1.50	3,000	3,450	CONP	51.69	178,300	388,300
22-25-35	Reinforcing		Est	180	TN	0.00	1,150.00	0	207,000		20.00	3,600	4,140	REIN	61.48	254,500	461,500
22-17-25	Formwork		Est	6,000	SF	0.00	2.50	0	15,000		0.14	810	932	FORM	71.62	66,700	81,700
22-15-25	Embedded steel		Est	5.00	TN	0.00	5,000.00	0	25,000		120.00	600	690	CARP	46.37	32,000	57,000
	SDA Superstructure	**Quantities are total for 2 units**															0
23-25-75	Common Penthouse for SDA's	support steel, roof steel, girts and purlins	Est	152	TN	0.00	2,650.00	0	402,500		35.00	5,316	6,113	STST	87.33	533,800	936,300
24-37-43	SDA Roof Insulation	between penthouse floor and SDA roof total for 2 SDAs	Est	12,070	SF	0.00	15.00	0	181,100		0.30	3,621	4,164	ROOF	45.55	189,700	370,800
24-37-47	Roofing for common SDA Penthouse	standing seam type.	Est	8,100	SF	0.00	18	0	145,800		0.22	1,782	2,049	ROOF	45.55	93,300	239,100
24-41-25	Siding for common SDA Penthouse	insulated metal siding	Est	16,200	SF	0.00	12	0	194,400		0.11	1,782	2,049	SDNG	63.02	129,100	323,500
36-13-23	Shell Insulation	subcontract cost	Est	61,688	SF	30.00	0	1,850,600	0			0	0	DINS	52.16	0	1,850,600
22-13-23	Concrete bottom floor for common SDA Penthouse	includes metal decking and formwork	Est	99	CY		210	0	20,800		7.5	743	854	CONP	51.69	44,100	64,900
41-37-99	Common Penthouse Building Services	H&V and Lighting	Est	8,100	SF	0.00	30.00	0	243,000		0.30	2,430	2,795	WIRE	66.93	187,000	430,000
31-41-77	Fire Protection for Penthouse	Standpipe & hose stations.	Est	2	LS	80,000		160,000			500.00	1,000	1,150	MECH	61.53	70,800	230,800
24-17-15	Elevator	For SDA - four person rack and pinion elevator. Suncontract price includes labor	Est	1	LT	290,000	0.00	290,000	0		0.00	0	0	MECH	61.53	0	290,000
22-13-37	Concrete pit for the elevator		Est	10	CY	0	210.00	0	2,100		7.5	75	86	CONP	51.69	4,500	6,600
41-99-99	Electrical work for the elevator	allowance	Est	1	LT	0	20,000.00	0	20,000		175	175	201	WIRE	66.93	13,500	33,500

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
	SDA - Support Steel and Access Gallery																
23-25-75	Support Steel	Included in DFGD equip.	Est	300	TN	0	0	0	0		20	6,000	6,900	STST	87.33	602,600	602,600
23-17-23	Walkway from U1 SDA's to U2 SDA's		Est	20	TN	0	0	0	0		35	700	805	STST	87.33	70,300	70,300
23-17-23	Access Gallery		Est	1,500	SF	0.00	35.00	0	52,500		0.40	600	690	GALL	67.14	46,300	98,800
27-17-99	Touch-up painting		Est	2	LT	0.00	45,000.00	0	90,000		1800.00	3,600	4,140	PNTR	56.92	235,600	325,600
	Reagent Handling / Preparation- Civil / Structural Work	One common for both units															0
	Foundations for Lime Storage Silo																
21-23-15	Excavation		Est	280	CY	0.00	0.00	0	0		0.20	56	64	EXFD	63.95	4,100	4,100
21-17-25	Backfill		Est	80	CY	0.00	0.00	0	0		0.30	24	28	EXFD	63.95	1,800	1,800
22-13-37	Concrete		Est	200	CY	0.00	105.00	0	21,000		1.50	300	345	CONP	51.69	17,800	38,800
22-25-35	Reinforcing		Est	18	TN	0.00	1,150.00	0	20,700		20.00	360	414	REIN	61.48	25,500	46,200
22-17-25	Formwork		Est	600	SF	0.00	2.50	0	1,500		0.14	81	93	FORM	71.62	6,700	8,200
22-15-25	Embedded steel		Est	0.50	TN	0.00	5,000.00	0	2,500		120.00	60	69	CARP	46.37	3,200	5,700
23-25-75	Support Steel for lime Storage Silo	Not required - concrete silo															
23-17-23	Galleries		Est	1,800	SF	0.00	35.00	0	63,000		0.40	720	828	GALL	67.14	55,600	118,600
23-17-53	Stair Tower for Lime Storage Silo		Est	120	TN	2,650	0	318,000	0		25	3,000	3,450	STST	87.33	301,300	619,300
31-41-77	Fire Protection	Standpipe & hose stations	Est	1	LS	60,000.00		60,000	0		400.00	400	460	YDPP	63.15	29,000	89,000
	Lime Preparation / Recycle Building (55' x 100' x 125'H)	Quantities shown are total for 2 buildings, 1/unit															
22	Substructure																0
21-23-15	Excavation		Est	1,070	CY		0.00	0	0		0.20	214	246	EXFD	63.95	15,700	15,700
21-17-25	Backfill		Est	70	CY		0.00	0	0		0.30	21	24	EXFD	63.95	1,500	1,500
22-13-37	Concrete		Est	1,000	CY		105.00	0	105,000		1.50	1,500	1,725	CONP	51.69	89,200	194,200
22-25-35	Reinforcing		Est	75	TN		1,150.00	0	86,300		20.00	1,500	1,725	REIN	61.48	106,100	192,400
22-17-25	Formwork		Est	3,000	SF		2.50	0	7,500		0.14	405	466	FORM	71.62	33,400	40,900
22-15-25	Embedded steel		Est	2.50	TN		5,000.00	0	12,500		120.00	300	345	CARP	46.37	16,000	28,500
	Superstructure																
23-25-75	Structural Steel		Est	900	TN		2650	0	2,384,400		16	14,396	16,556	STST	87.33	1,445,800	3,830,200
24-41-25	Insulated Metal Siding		Est	80,000	SF		12	0	960,000		0.11	8,800	10,120	SDNG	63.02	637,800	1,597,800
24-15-15	Rolling Overhead Door	one for each building	Est	640	SF		27	0	17,300		0.25	160	184	CARP	46.37	8,500	25,800
23-23-23	Metal Roof Decking		Est	11,000	SF		2.7	0	29,700		0.06	660	759	STST	87.33	66,300	96,000
24-37-43	Rigid Roof Insulation, 2" Thick		Est	11,000	SF		2.4	0	26,400		0.015	165	190	ROOF	45.55	8,600	35,000
24-37-17	Cant Strips, Treated		Est	620	LF		1.32	0	800		0.035	22	25	ROOF	45.55	1,100	1,900
24-37-73	Roofing (4-Ply Tar & Gravel)		Est	11,000	SF		1.55	0	17,100		0.04	440	506	ROOF	45.55	23,000	40,100
22-13-43	Lightweight Concrete Fill 1"		Est	247	CY		100	0	24,700		1.3	321	369	ROOF	45.55	16,800	41,500
24-37-27	Roof Flashing		Est	620	LF		14.45	0	9,000		0.12	74	86	ROOF	45.55	3,900	12,900
35-13-31	Roof Drains		Est	2	LT		20000	0	40,000		250	500	575	PLMB	47.74	27,500	67,500
35-13-31	Floor Drains		Est	2	LT		25000	0	50,000		300	600	690	PLMB	47.74	32,900	82,900
22-13-23	Floor Slabs	includes metal decking and formwork	Est	101	CY		210	0	21,200		7.5	756	870	CONP	51.69	45,000	66,200
22-13-23	Floor Finishes		Est	8,250	SF		2.5	0	20,600		0.05	413	474	CONP	51.69	24,500	45,100
24-25-25	Louvers/Windows/Doors		Est	8,000	SF		40	0	320,000		0.5	4,000	4,600	CONP	51.69	237,800	557,800
34-41-99	Roof Ventilators		Est	8	EA		15000	0	120,000		24	192	221	HVAC	51.91	11,500	131,500
23-17-23	Galleries & Landings		Est	800	SF		45	0	36,000		0.4	320	368	GALL	67.14	24,700	60,700
34-55-99	H&V		Est	11,000	SF		16.7	0	183,300		0.17	1,833	2,108	HVAC	51.91	109,400	292,700
41-37-99	Electrical Service & Lighting		Est	11,000	SF		20.0	0	220,000		0.20	2,200	2,530	WIRE	66.93	169,300	389,300
31-41-77	Fire Protection	Standpipe & hose stations	Est	2	LS	60,000.00		120,000	0		400.00	800	920	YDPP	63.15	58,100	178,100
23	**Pipe Rack For Lime Handling, Waste Ash Handling and misc Mechanical Piping**	**Quantities shown are total for 2 units**															
23-25-75	Structure and Support Steel		Est	330	TN	0.00	2,650.00	0	874,500		20.00	6,600	7,590	STST	87.33	662,800	1,537,300
22	Foundations for support steel							0	0								0
21-23-15	Excavation		Est	1,292	CY	0.00	0.00	0	0		0.20	258	297	EXFD	63.95	19,000	19,000
21-17-25	Backfill		Est	342	CY	0.00	0.00	0	0		0.30	103	118	EXFD	63.95	7,500	7,500
22-13-37	Concrete		Est	950	CY	0.00	105.00	0	99,800		1.50	1,425	1,639	CONP	51.69	84,700	184,500
22-25-35	Reinforcing		Est	71	TN	0.00	1,150.00	0	81,900		20.00	1,425	1,639	REIN	61.48	100,800	182,700
22-17-25	Formwork		Est	9,500	SF	0.00	2.50	0	23,800		0.14	1,283	1,475	FORM	71.62	105,600	129,400
22-15-25	Embedded Steel		Est	4,750	LB	0.00	2.50	0	11,900		0.05	238	273	CARP	46.37	12,700	24,600
22	Foundations for Misc. Support Steel	Quantities shown are total for 2 units						0	0								0
21-23-15	Excavation		Est	272	CY	0.00	0.00	0	0		0.20	54	63	EXFD	63.95	4,000	4,000
21-17-25	Backfill		Est	72	CY	0.00	0.00	0	0		0.30	22	25	EXFD	63.95	1,600	1,600
22-13-37	Concrete		Est	200	CY	0.00	105.00	0	21,000		1.50	300	345	CONP	51.69	17,800	38,800
22-25-35	Reinforcing		Est	15	TN	0.00	1,150.00	0	17,300		20.00	300	345	REIN	61.48	21,200	38,500
22-17-25	Formwork		Est	2,000	SF	0.00	2.50	0	5,000		0.14	270	311	FORM	71.62	22,200	27,200
22-15-25	Embedded Steel		Est	1,000	LB	0.00	2.50	0	2,500		0.05	50	58	CARP	46.37	2,700	5,200

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
23-25-75	Misc. Support Steel not included elsewhere	Quantities shown are total for 2 units	Est	100	TN	0	2,650	0	265,000		20	2,000	2,300	STST	87.33	200,900	465,900
23-17-23	Misc. Galleries	Quantities shown are total for 2 units	Est	3,000	SF	0.00	35.00	0	105,000		0.40	1,200	1,380	GALL	67.14	92,700	197,700
	Fabric Filter							**24,079,500**	**4,622,500**				**279,365**			**17,633,000**	**46,335,000**
31-57-15	Fabric Filter System		Q	2	LT	9,912,416	0.00	19,824,800	0		80,500	161,000	185,150	MECH	61.53	11,392,300	31,217,100
31-17-45	Fabric Filter Baghouse Air Compressor System		Q	2	LT	2,027,372	0.00	4,054,700	0		17,900	35,800	41,170	MECH	61.53	2,533,200	6,587,900
35-13-15	Fabric Filter Baghouse Compressor System Piping	Included in air compressor system pricing	Est	2	LT	0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-27-35	Fabric Filter Bypass Dampers	Included in Fabric Filter System Price	Est	2	LT	0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-57-99	Hopper Heaters	Included in Fabric Filter System Price	Est	2	LT	0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-57-99	Vent Fan	Included in Fabric Filter System Price	Est	2	LT	0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-25-35	Hoist & Trolley Beam	Included in Fabric Filter System Price	Est	2	LT	0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
36-13-23	Insulation for Baghouse	subcontract cost	Est	65,111	SF	0.00	30.00	0	1,953,300		0	0	0	DINS	52.16	0	1,953,300
23-25-75	Penthouse steel for baghouses	Support steel, roof steel, girts and purlins.	Est	79	TN	0.00	2,650.00	0	209,300		35.00	2,765	3,179	STST	87.33	277,600	486,900
24-41-25	Siding for baghouse penthouse	insulated metal siding	Est	12,960	SF	0.00	12	0	155,500		0.11	1,426	1,639	SDNG	63.02	103,300	258,800
24-37-47	Roofing for baghouse penthouse	standing seam type	Est	5,751	SF	0.00	18	0	103,500		0.22	1,265	1,455	ROOF	45.55	66,300	169,800
22-13-23	Concrete bottom floor for baghouse penthouse	includes metal decking and formwork	Est	70	CY		210	0	14,800		7.5	527	606	CONP	51.69	31,300	46,100
41-37-99	Building Services	H&V and Lighting	Est	5,751	SF	0.00	22.00	0	126,500		0.20	1,150	1,323	WIRE	66.93	88,500	215,000
31-41-77	Fire Protection for Penthouse	Standpipe & hose stations	Est	2	LS	60,000.00		120,000			400.00	800	920	MECH	61.53	56,600	176,600
23-25-75	Bottom Enclosure steel	Support steel, girts and purlins. Total for Units 1&2	Est	171	TN	0.00	2,650.00	0	453,900		20	3,426	3,939	STST	87.33	344,000	797,900
41-37-99	Building Services	H&V and Lighting	Est	19,880	SF	0.00	22.00	0	437,400		0.20	3,976	4,572	WIRE	66.93	306,000	743,400
24-41-25	Siding for baghouse bottom enclosure	insulated metal siding, support steel and girts included in Alstom pricing	Est	17,976	SF	0.00	12	0	215,700		0.11	1,977	2,274	SDNG	63.02	143,300	359,000
31-41-77	Fire Protection for bottom enclosure	Standpipe & hose stations	Est	2	LS	40,000.00	0.00	80,000	0		300.00	600	690	MECH	61.53	42,500	122,500
	Fabric Filter System - Structural																0
	Foundations for Fabric Filter Baghouse	Quantities shown are total for 2 units															
21-23-15	Excavation		Est	3,852	CY	0.00	0.00		0		0.20	770	886	EXFD	63.95	56,700	56,700
21-17-25	Backfill		Est	252	CY	0.00	0.00		0		0.30	76	87	EXFD	63.95	5,600	5,600
22-13-37	Concrete		Est	3,600	CY	0.00	105.00	0	378,000		1.50	5,400	6,210	CONP	51.69	321,000	699,000
22-25-35	Reinforcing		Est	324	TN	0.00	1,150.00	0	372,600		20.00	6,480	7,452	REIN	61.48	458,100	830,700
22-17-25	Formwork		Est	10,800	SF	0.00	2.50	0	27,000		0.14	1,458	1,677	FORM	71.62	120,100	147,100
22-15-25	Embedded Steel		Est	9.00	TN	0.00	5,000.00		45,000		120.00	1,080	1,242	CARP	46.37	57,600	102,600
	Support Steel and Access Gallery																0
23-25-75	Support Steel	Included in Baghouse equip price	Q	420	TN	0.00	0	0	0		25	10,500	12,075	STST	87.33	1,054,500	1,054,500
23-17-23	Access Gallery		Q	3,000	SF	0.00	35.00	0	105,000		0.40	1,200	1,380	GALL	67.14	92,700	197,700
27-17-99	Touch-up painting		Est	1	LT	0.00	25,000.00	0	25,000		1250.00	1,250	1,438	PNTR	56.92	81,800	106,800
																	0
	Ash Recycling System - DFGD Contractor's Scope							**6,843,000**	**0**				**69,460**			**4,273,900**	**11,116,900**

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man-hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
31-45-99	**Ash Recycling System - Mechanical**			2	LT	3,421,528		6,843,000			30200	60,400	69,460	MECH	61.53	4,273,900	11,116,900
31-45-99	Recycle Ash Storage Silo	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Ash Silo Bin Vent	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Ash Fluidizing Air Blower	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Ash Fluidizing Air Heater	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Ash Silo Discharge Rotary Feeder	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Slurry Vibrating Screen	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Ash Prep Area Sump Tank	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Ash Prep Area Sump Tank Agitator	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Ash Slurry Mix Tank	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Ash Slurry Mix Tank Agitator	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Slurry Storage Tank	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Slurry Storage Tank Agitator	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
31-45-99	Recycle Slurry Feed Pumps	Included in Ash Recycling System Price	Q			0.00	0.00	0	0		0	0	0	MECH	61.53	0	0
	Ash Recycling System - BOP Scope							**60,000**	**534,800**				**4,583**			**360,800**	**955,600**
	Ash Reagent Recycle Building	Included with Lime Preparation Building															
24-35	**Ash Handling Blower Building (25' x 50' x 25'H)**	Quantities shown are total for 2 buildings, 1/unit															
22-13	Substructure																0
21-23-15	Excavation		Est	214	CY	0.00	0.00	0	0		0.20	43	49	EXFD	63.95	3,100	3,100
21-17-25	Backfill		Est	14	CY	0.00	0.00	0	0		0.30	4	5	EXFD	63.95	300	300
22-13-37	Concrete		Est	200	CY	0.00	105.00	0	21,000		1.50	300	345	CONP	51.69	17,800	38,800
22-25-35	Reinforcing		Est	15	TN	0.00	1,150.00	0	17,300		20.00	300	345	REIN	61.48	21,200	38,500
22-17-25	Formwork		Est	800	SF	0.00	2.50	0	2,000		0.14	108	124	FORM	71.62	8,900	10,900
22-15-25	Embedded Steel		Est	1,600	LB	0.00	2.50	0	4,000		0.05	80	92	CARP	46.37	4,300	8,300
24-35-25	Pre-engineered building	Includes H&V and Lighting	Est	2,500	SF	0.00	175.00	0	437,500		0.90	2,250	2,588	STST	87.33	226,000	663,500
23-25-75	Additional Support Steel for Waste Ash Pipes	outside of pipe rack	Est	20	TN	0.00	2,650.00	0	53,000		25.00	500	575	STST	87.33	50,200	103,200
31-41-77	Fire Protection	Standpipe & hose stations	Est	2	LS	30,000		60,000			200.00	400	460	YDPP	63.15	29,000	89,000
																	0
	Waste Ash and Fly Ash Handling System							**10,131,300**	**339,300**				**60,951**			**3,795,000**	**14,265,600**
33	**Waste Ash Handling System - Mechanical**																0
26-13-15	Waste Ash silo	Concrete silo - subcontract price	Q	1	LT	1,550,000	0.00	1,550,000	0		0.00	0	0	CONP	51.69	0	1,550,000
24-17-15	Elevator for waste ash silo	maintenance elevator - subcontract price	Est	1	LT	290,000	0.00	290,000	0		0	0	0	MECH	61.53	0	290,000
22-13-27	Concrete pit for the elevator	total for 2 silo elevators	Est	10	CY	0	210.00	0	2,100		7.5	75	86	CONP	51.69	4,500	6,600
41-99-99	Electrical work for the elevator	allowance	Est	1	LT	0	20,000.00	0	20,000		175	175	201	WIRE	66.93	13,500	33,500
33-13-45	Waste Handling Systsem	Includes blowers, ash valves, and ash piping	Q	1	LT	5,300,000	0.00	5,300,000	0		30,000	30,000	34,500	MECH	61.53	2,122,800	7,422,800
33-13-45	Mechanical Equipment		Est			0	0.00	0	0		0	0	0	MECH	61.53	0	0
33-13-45	Mechanical Blowers	Included in Waste Handling System Price	Est			0	0.00	0	0		0	0	0	MECH	61.53	0	0

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
33-13-45	Waste Ash Silo Unloading Equipment including Fluidizing Blowers	Included in Waste Handling System Handling Price	Est			0	0.00	0	0		0	0	0	MECH	61.53	0	0
33-13-45	Waste Ash Vacuum Pipes from FF hoppers to Filter Separators	Included in Waste Handling System Handling Price	Est			0	0.00	0	0		0	0	0	MECH	61.53	0	0
33-13-45	Motor Operated Butterfly Valves	Included in Waste Handling System Handling Price	Est			0	0.00	0	0		0	0	0	MECH	61.53	0	0
22-13-75	Fly Ash Silo	Field erected steel silo. Pricing includes mechanical equipment and ash piping	Est	75	TN	4,000	0.00	300,000	0		70	5,250	6,038	TANK	61.57	371,700	671,700
33-13-45	Mechanical equipment for ash handling system and silo fly ash unloading equipment		Est	1	LT	2,500,000	0.00	2,500,000	0		10,000	10,000	11,500	MECH	61.53	707,600	3,207,600
	Foundations for Fly Ash Silo																0
21-23-15	Excavation		Est	80	CY	0.00	0.00		0		0.20	16	18	EXFD	63.95	1,200	1,200
21-17-25	Backfill		Est	30	CY	0.00	0.00		0		0.30	9	10	EXFD	63.95	700	700
22-13-37	Concrete		Est	50	CY	0.00	105.00	0	5,300		1.50	75	86	CONP	51.69	4,500	9,800
22-25-35	Reinforcing		Est	5	TN	0.00	1,150.00	0	5,200		20.00	90	104	REIN	61.48	6,400	11,600
22-17-25	Formwork		Est	150	SF	0.00	2.50	0	400		0.14	20	23	FORM	71.62	1,700	2,100
22-15-25	Embedded Steel		Est	0.13	TN	0.00	5,000.00		600		120.00	15	17	CARP	46.37	800	1,400
23-25-75	Support Steel for Fly Ash Storage Silo		Est	50	TN	0.00	2,650.00	0	132,500		35.00	1,750	2,013	STST	87.33	175,800	308,300
23-17-23	Access Gallery for fly ash silo	Included with Misc Galleries.		0	SF	0	35	0	0		0.40	0	0	GALL	67.14	0	0
33-57-65	Truck Scale		Est	1	LT	125,000	0	125,000	0		900	900	1,035	MECH	61.53	63,700	188,700
22-13-37	Concrete foundation and approach for truck scale		Est	350	CY	0	210	0	73,500		7.50	2,625	3,019	CONP	51.69	156,000	229,500
41-99-99	Electrical allowance for truck scale		Est	1	LT	0	15,000	0	15,000		200.00	200	230	WIRE	66.93	15,400	30,400
	Foundations for Waste Ash Silo																0
21-23-15	Excavation		Est	176	CY	0.00	0.00		0		0.20	35	40	EXFD	63.95	2,600	2,600
21-17-25	Backfill		Est	66	CY	0.00	0.00		0		0.30	20	23	EXFD	63.95	1,500	1,500
22-13-37	Concrete		Est	110	CY	0.00	105.00	0	11,600		1.50	165	190	CONP	51.69	9,800	21,400
22-25-35	Reinforcing		Est	10	TN	0.00	1,150.00	0	11,400		20.00	198	228	REIN	61.48	14,000	25,400
22-17-25	Formwork		Est	330	SF	0.00	2.50	0	800		0.14	45	51	FORM	71.62	3,700	4,500
22-15-25	Embedded Steel		Est	0.28	TN	0.00	5,000.00		1,400		120.00	33	38	CARP	46.37	1,800	3,200
23-25-75	Support Steel for Waste Ash Storage Silo	concrete silo	Est	0	TN	0.00	2,650.00	0	0		35.00	0	0	STST	87.33	0	0
23-17-53	Stair Tower for Waste Ash Silo		Est	25	TN	2,650	0	66,300	0		25	625	719	STST	87.33	62,800	129,100
23-17-23	Access Gallery for waste ash silo		Est	1,700	SF	0	35	0	59,500		0.40	680	782	GALL	67.14	52,500	112,000
																	0
	Flue Gas System							**5,558,000**	**14,067,000**				**338,089**			**22,838,000**	**42,463,000**
	Spray Dryer Absorber Inlet Duct (from Existing ID Fan Outlet)	Quantities are total for 2 units															0
23-15-35	Ductwork Steel, including plate, stiffeners, internal bracing, turning vanes and walkway grating		Est	1,600	TN	0.00	3,250.00	0	5,200,000		60.00	96,000	110,400	FLDU	77.18	8,520,700	13,720,700
36-13-57	Insulation & Lagging		Est	152,000	SF	0.00	12.00	0	1,824,000		0.26	39,520	45,448	DINS	52.16	2,370,600	4,194,600
31-33-15	Expansion Joints		Est	3,200	LF	0.00	230.00	0	736,000		2.50	8,000	9,200	MECH	61.53	566,100	1,302,100
31-27-35	Dampers	Not Required															
44-21-99	Dry FGD Inlet Ductwork Instrumentation		Est	4	LS	30,000.00	0.00	120,000	0		200	800	920	INEL	54.22	49,900	169,900
	Spray Dryer Absorber Outlet to Fabric Filter Inlet	Quantities are total for 2 units															0
23-15-35	Ductwork Steel, including plate, stiffeners, internal bracing, turning vanes and walkway grating	included in DFGD equipment supply pricing															
36-13-57	Insulation & Lagging		Allow	50,000	SF	0.00	12.00	0	600,000		0.26	13,000	14,950	DINS	52.16	779,800	1,379,800
31-33-15	Expansion Joints	Material price is included in DFGD contract cost	Est	275	LF	0.00	0.00	0	0		2.50	688	791	MECH	61.53	48,600	48,600
44-21-99	Dry FGD Outlet Ductwork Instrumentation	Material price is included in DFGD contract cost	Est	1	LS	0.00	0.00	0	0		200	200	230	INEL	54.22	12,500	12,500
31-27-35	Dampers	Not required	Est	0	SF	450.00	0.00	0	0		3.00	0	0	MECH	61.53	0	0
	Fabric Filter Outlet Duct to Booster Fans and Booster ID Fans to existing chimney breeching	Quantities are total for 2 units															0

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
23-15-35	Ductwork Steel, including plate, stiffeners, internal bracing, turning vanes and walkway grating		Est	560	TN	0.00	3,250.00	0	1,820,000		60.00	33,600	38,640	FLDU	77.18	2,982,200	4,802,200
36-13-57	Insulation & Lagging		Est	56,000	SF	0.00	12.00	0	672,000		0.26	14,560	16,744	DINS	52.16	873,400	1,545,400
31-33-15	Expansion Joints		Est	1,800	LF	0.00	230.00	0	414,000		2.50	4,500	5,175	MECH	61.53	318,400	732,400
31-27-35	Dampers	Not required	Est	0	SF	450.00	0.00	0	0		2.50	0	0	MECH	61.53	0	0
44-21-99	Fabric Filter Outlet Ductwork Instrumentation		Est	4	LS	30,000.00	0.00	120,000	0		200	800	920	INEL	54.22	49,900	169,900
	Booster ID Fans	Quantities are total for 2 units															0
31-35-15	New Booster ID Fans	Axial fan, 2 x 50% per unit, 882,450 cfm, includes fan auxiliary equipment	Est	4	EA	775,000	0.00	3,100,000	0		3000.00	12,000	13,800	MECH	61.53	849,100	3,949,100
41-43-35	Motors for Booster ID Fans	3300 HP	Est	4	EA	247,000	0.00	988,000	0		1000.00	4,000	4,600	MECH	61.53	283,000	1,271,000
31-25-35	Hoist & trolleys for Booster ID Fans	5-ton cap	Est	4	EA	15,000	0.00	60,000	0		150.00	600	690	MECH	61.53	42,500	102,500
36-13-23	Fan Insulation & Lagging	total for two fans	Est	6,000	SF	0.00	12.00	0	72,000		0.28	1,680	1,932	DINS	52.16	100,800	172,800
31-27-35	Booster ID Fans Isolation Dampers	Single Louver type damper assembly	Est	2,400	SF	450.00	0.00	1,080,000	0		2.50	6,000	6,900	MECH	61.53	424,600	1,504,600
	Flue Gas System - Structural																
	Ductwork Support Foundations	Total for all ductwork for 2 units															0
21-23-15	Excavation		Est	2,140	CY	0.00	0.00		0		0.20	428	492	EXFD	63.95	31,500	31,500
21-17-25	Backfill		Est	140	CY	0.00	0.00		0		0.30	42	48	EXFD	63.95	3,100	3,100
22-13-37	Concrete		Est	2,000	CY	0.00	105.00	0	210,000		1.50	3,000	3,450	CONP	51.69	178,300	388,300
22-25-35	Reinforcing		Est	150	TN	0.00	1,150.00	0	172,500		20.00	3,000	3,450	REIN	61.48	212,100	384,600
22-17-25	Formwork		Est	6,000	SF	0.00	2.50	0	15,000		0.14	810	932	FORM	71.62	66,700	81,700
22-15-25	Embedded Steel		Est	5.00	TN	0.00	5,000.00		25,000		120.00	600	690	CARP	46.37	32,000	57,000
23-25-75	Structural Steel Duct Supports		Est	580	TN	0.00	2,650.00	0	1,537,000		35.00	20,300	23,345	STST	87.33	2,038,700	3,575,700
	ID Fan Foundations	Quantities are total for 2 units							0								0
21-23-15	Excavation		Est	2,033	CY	0.00	0.00		0		0.20	407	468	EXFD	63.95	29,900	29,900
21-17-25	Backfill		Est	133	CY	0.00	0.00		0		0.30	40	46	EXFD	63.95	2,900	2,900
22-13-37	Concrete		Est	1,900	CY	0.00	105.00	0	199,500		1.50	2,850	3,278	CONP	51.69	169,400	368,900
22-25-35	Reinforcing		Est	143	TN	0.00	1,150.00	0	163,900		20.00	2,850	3,278	REIN	61.48	201,500	365,400
22-17-25	Formwork		Est	15,200	SF	0.00	2.50	0	38,000		0.14	2,052	2,360	FORM	71.62	169,000	207,000
22-15-25	Embedded Steel		Est	9.50	TN	0.00	5,000.00	0	47,500		120.00	1,140	1,311	CARP	46.37	60,800	108,300
23-17-23	Access Gallery for all inlet and outlet ductwork		Est	3,000	SF	0	35.00	0	105,000		0.40	1,200	1,380	GALL	67.14	92,700	197,700
41-37-43	Lighting for access galleries and Booster Fan area		Est	6,000	SF	0.00	15.00	0	90,000		0.15	900	1,035	WIRE	66.93	69,300	159,300
	Stack Coating	**Acid resistant coating - top 50 ft of liner. Assumed chimney liner 20Ft dia x 500 ft high**															
61-23-35	Suspended Motorized Modular Platform Rental	90 day rental, each stack	Est.	2	LT	45,000.00	0.00	90,000	0		300.00	600	690	CARP	46.37	32,000	122,000
27-15-35	Prep and clean top 50ft of two flues (inside only) to white metal (SSPC-SP 5)	Quantities shown are for 2 stacks. Includes misc. repairs	Est.	6,400	SF	0.00	0.00	0	0		1.33	8,512	9,789	PNTR	56.92	557,200	557,200
27-13-99	Apply acid resistant coating	Quantities shown are for 2 stacks.	Est.	6,400	SF	0.00	16.50	0	105,600		1.33	8,512	9,789	PNTR	56.92	557,200	662,800
61-17-43	Temporary Power, Light and Ventilation		Est.	2	LT	0.00	10,000.00	0	20,000		400.00	800	920	WIRE	66.93	61,600	81,600
	Mechanical - Balance of Plant							**0**	**2,913,900**				**60,105**			**3,977,400**	**6,891,300**
	Piping																
	Vacuum Conveying																
35-13-99	Vacuum conveying to lime silo		Est		LF	0.00	57.60	0	0		1.50	0	0	SPNG	67.64	0	0
	Makeup Water																
35-13-15	8" CS, SCH 40, includes fittings, underground	Raw water to reagent prep	Est	1,130	LF	0.00	130.20	0	147,100		1.88	2,124	2,443	YDPP	63.15	154,300	301,400
35-13-15	6" CS, SCH 40, includes fittings, underground	Raw water to reagent prep	Est	120	LF	0.00	89.50	0	10,700		1.60	192	221	YDPP	63.15	13,900	24,600
21-25-15	Excavation for Underground Piping		Est	628	CY	0.00	0.00	0	0		0.20	126	144	EXFD	63.95	9,200	9,200
21-17-15	Bedding for Underground Piping		Est	94	CY	0.00	40.00	0	3,800		0.30	28	32	EXFD	63.95	2,100	5,900

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
21-17-25	Backfill for Underground Piping		Est	534	CY	0.00	0.00	0	0		0.30	160	184	EXFD	63.95	11,800	11,800
35-13-15	2.5" CS, SCH 40, includes fittings	Slaker water and dilution water	Est	320	LF	0.00	35.60	0	11,400		1.28	410	471	SPNG	67.64	31,900	43,300
35-13-15	2.5" CS, SCH 80, includes fittings	Slaker water and dilution water	Est	320	LF	0.00	55.50	0	17,800		1.44	461	530	SPNG	67.64	35,800	53,600
35-13-15	4" CS, SCH 40, includes fittings	Recycle water	Est	1,190	LF	0.00	57.60	0	68,500		1.50	1,785	2,053	SPNG	67.64	138,800	207,300
35-13-33	Pipe Supports for Makeup Water piping		Est	2.58	TN	0.00	2,650.00	0	6,800		40.00	103	119	STST	87.33	10,400	17,200
	Service Water																
35-13-15	6" CS, SCH 40, includes fittings, underground	Extend existing service water line to new lime unloading area	Est	810	LF	0.00	89.50	0	72,500		1.60	1,296	1,490	YDPP	63.15	94,100	166,600
35-13-15	3" CS, SCH 40, includes fittings, underground	Reagent prep building abd fly ash silos	Est	1,520	LF	0.00	48.80	0	74,200		1.37	2,082	2,395	YDPP	63.15	151,200	225,400
21-25-15	Excavation for Underground Piping		Est	1,294	CY	0.00	0.00	0	0		0.20	259	298	EXFD	63.95	19,000	19,000
21-17-15	Bedding for Underground Piping		Est	194	CY	0.00	40.00	0	7,800		0.30	58	67	EXFD	63.95	4,300	12,100
21-17-25	Backfill for Underground Piping		Est	1,100	CY	0.00	0.00	0	0		0.30	330	380	EXFD	63.95	24,300	24,300
35-13-15	3" CS, SCH 40, includes fittings	Absorbers (penthouse)	Est	680	LF	0.00	48.80	0	33,200		1.37	932	1,071	SPNG	67.64	72,500	105,700
35-15-15	2" CS, SCH 80, includes fittings	Reagent prep building, absorbers (penthouse), fly ash silos	Est	600	LF	0.00	39.80	0	23,900		1.36	816	938	SPNG	67.64	63,500	87,400
35-13-33	Pipe Supports for Service Water piping		Est	1.51	TN	0.00	2,650.00	0	4,000		40.00	60	69	STST	87.33	6,100	10,100
	Lime Slurry Pipe																
35-13-15	2.5" CS, SCH 80, includes fittings	Reagent prep to atomizer head tank in SDA	Est	1,200	LF	0.00	55.50	0	66,600		1.44	1,728	1,987	SPNG	67.64	134,400	201,000
35-13-33	Pipe Supports for Service Water piping		Est	1.76	TN	0.00	2,650.00	0	4,700		40.00	70	81	STST	87.33	7,100	11,800
	Ash Pipe																
35-13-99	10" Ashcolite, flanged	Supports included with pipe rack	Est	1,440	LF	0.00	165.00	0	237,600		1.75	2,520	2,898	YDPP	63.15	183,000	420,600
35-13-33	Pipe supports within building boundaries		Est	10	EA	0.00	125.00	0	1,300		3.00	30	35	STST	87.33	3,000	4,300
	Recycle Slurry Pipe																
35-13-15	6" CS, SCH 80, includes fittings, underground	Recycle ash silo to atomizer head tank	Est	1,200	LF	0.00	135.20	0	162,200		1.94	2,328	2,677	YDPP	63.15	169,100	331,300
35-13-33	Pipe Supports for Recycle Slurry piping		Est	4.28	TN	0.00	2,650.00	0	11,400		40.00	171	197	STST	87.33	17,200	28,600
	Slurry Return Pipe																
35-13-15	6" CS, SCH 80, includes fittings, underground	SDA to reagent prep	Est	1,200	LF	0.00	135.20	0	162,200		1.94	2,328	2,677	YDPP	63.15	169,100	331,300
35-13-33	Pipe Supports for Recycle Slurry piping		Est	4.28	TN	0.00	2,650.00	0	11,400		40.00	171	197	STST	87.33	17,200	28,600
	Sump Discharge / Drains																
35-13-15	2.5" CS, SCH 40, includes fittings	Absorber and Prep Building	Est	260	LF	0.00	35.60	0	9,300		1.28	333	383	SPNG	67.64	25,900	35,200
35-13-15	4" CS, SCH 40, includes fittings	Reagent prep building	Est	3,250	LF	0.00	57.60	0	187,200		1.50	4,875	5,606	SPNG	67.64	379,200	566,400
35-13-33	Pipe Supports for Sump Discharge and Drains		Est	5.19	TN	0.00	2,650.00	0	13,800		40.00	208	239	STST	87.33	20,900	34,700
35-13-21	3" HDPE includes fittings	Undeground. Absorber Sumps	Est	580	LF	0.00	4.80	0	2,800		1.37	795	914	SPNG	67.64	61,800	64,600
35-13-21	4" HDPE includes fittings	Fly Ash Silos, Lime Silos	Est	3,620	LF	0.00	4.80	0	17,400		1.48	5,358	6,161	SPNG	67.64	416,700	434,100
21-25-15	Excavation for Underground Piping		Est	1,556	CY	0.00	0.00	0	0		0.20	311	358	EXFD	63.95	22,900	22,900
21-17-15	Bedding for Underground Piping		Est	233	CY	0.00	40.00	0	9,300		0.30	70	81	EXFD	63.95	5,100	14,400
21-17-25	Backfill for Underground Piping		Est	1,322	CY	0.00	0.00	0	0		0.30	397	456	EXFD	63.95	29,200	29,200
	Fire Protection																
35-13-35	6" HDPE, includes fittings	Extend existing and new for Absorber, Reagent Prep, Fly Ash Silos and Lime Silos	Est	1,640	LF	0.00	8.50	0	13,900		0.60	984	1,132	SPNG	67.64	76,500	90,400
21-25-15	Excavation for Underground Piping		Est	759	CY	0.00	0.00	0	0		0.20	152	175	EXFD	63.95	11,200	11,200
21-17-15	Bedding for Underground Piping		Est	114	CY	0.00	40.00	0	4,600		0.30	34	39	EXFD	63.95	2,500	7,100
21-17-25	Backfill for Underground Piping		Est	645	CY	0.00	0.00	0	0		0.30	194	223	EXFD	63.95	14,200	14,200
35-13-15	3" CS, SCH 40, includes fittings	Absorber, Reagent Prep, Fly Ash Silos and Lime Silos	Est	1,120	LF	0.00	48.80	0	54,700		1.37	1,534	1,765	SPNG	67.64	119,400	174,100
35-13-33	Pipe Supports for Fire Protection		Est	1.44	TN	0.00	2,650.00	0	3,800		40.00	58	66	STST	87.33	5,800	9,600
	Service Air																

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man-hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
35-13-15	3" CS, SCH 40, includes fittings	Absorber, Reagent Prep, Fly Ash Silos and Lime Silos	Est	2,980	LF	0.00	48.80	0	145,400		1.37	4,083	4,695	SPNG	67.64	317,600	463,000
35-15-15	2" CS, SCH 80, includes fittings	Reagent prep building, absorbers (penthouse), fly ash silos	Est	1,000	LF	0.00	39.80	0	39,800		1.36	1,360	1,564	SPNG	67.64	105,800	145,600
35-13-33	Pipe Supports for Service Air		Est	4.89	TN	0.00	2,650.00	0	13,000		40.00	196	225	STST	87.33	19,700	32,700
	Instrument Air																
35-15-13	2" 304SS, SCH 80, welded	Absorber, Reagent Prep, Fly Ash Silos and Lime Silos	Est	2,300	LF	0.00	101.42	0	233,300		1.63	3,743	4,305	SPNG	67.64	291,200	524,500
35-15-13	1.5" 304SS, SCH 80, welded	Fly Ash Silos and Lime Silos	Est	680	LF	0.00	73.37	0	49,900		1.51	1,028	1,182	SPNG	67.64	80,000	129,900
35-15-13	1" 304SS, SCH 80, welded	Absorber, Reagent Prep, Fly Ash Silos and Lime Silos	Est	1,140	LF	0.00	44.22	0	50,400		1.46	1,664	1,913	SPNG	67.64	129,400	179,800
35-13-33	Pipe Supports for Instrument Air		Est	8.81	TN	0.00	2,650.00	0	23,400		40.00	352	405	STST	87.33	35,400	58,800
	Valves																
31-41-47	Hydrants		Est	4	EA	0.00	1,500.00	0	6,000		6.00	24	28	YDPP	63.15	1,700	7,700
35-13-41	Valves with PIVS	6", CI	Est	6	EA	0.00	575.00	0	3,500		6.00	36	41	YDPP	63.15	2,600	6,100
35-15-41	1" CS Ball		Est	4	EA	0.00	150.00	0	600		3.00	12	14	SPNG	67.64	900	1,500
35-15-41	2" Bronze, Ball		Est	4	EA	0.00	750.00	0	3,000		4.00	16	18	SPNG	67.64	1,200	4,200
35-13-41	3" CS, Globe, welded		Est	32	EA	0.00	1,800.00	0	57,600		4.00	128	147	SPNG	67.64	10,000	67,600
35-13-41	6" CS Knifegate, welded		Est	4	EA	0.00	3,200.00	0	12,800		8.00	32	37	SPNG	67.64	2,500	15,300
35-13-41	8" CS Knifegate, welded		Est	20	EA	0.00	4,800.00	0	96,000		10.00	200	230	SPNG	67.64	15,600	111,600
35-13-41	12" CS Knifegate, welded		Est	8	EA	0.00	7,200.00	0	57,600		14.00	112	129	SPNG	67.64	8,700	66,300
35-15-41	Small bore valves, CS wededl	Allowance	Est	1	LT	0.00	10,000.00	0	10,000		60.00	60	69	SPNG	67.64	4,700	14,700
31-75-17	Makeup Water pumps	1000 gpm, 200 ft TDH	Est	2	EA	0.00	30,000.00	0	60,000		40.00	80	92	MECH	61.53	5,700	65,700
31-75-93	Sump Pumps	440 gpm, 220 TDH	Est	8	EA	0.00	25,000.00	0	200,000		30.00	240	276	MECH	61.53	17,000	217,000
31-17-45	Air compressors	250 SCFM, 100 psig	Est	2	EA	0.00	45,000.00	0	90,000		60.00	120	138	MECH	61.53	8,500	98,500
31-17-65	Air receivers	1000 Gal	Est	2	EA	0.00	7,000.00	0	14,000		20.00	40	46	MECH	61.53	2,800	16,800
31-17-55	Air dryers	250 net SCFM, 100 psig	Est	2	EA	0.00	15,000.00	0	30,000		30.00	60	69	MECH	61.53	4,200	34,200
31-65-99	In-line electric water heaters (boilers)	475 kW	Est	2	EA	0.00	17,200.00	0	34,400		80.00	160	184	MECH	61.53	11,300	45,700
41-99-99	Allowance for electrical work for the electric boiler		Allow	2	EA	0.00	5,000.00	0	10,000		20.00	40	46	WIRE	66.93	3,100	13,100
41	**Heat Tracing for Instrumentation Piping**																0
41-33-65	Heat tracing cable		Allow.	5,700	LF	0.00	10.35	0	59,000		0.05	285	328	WIRE	66.93	21,900	80,900
36-15	Insulation for heat traced piping	Assumed nominal 4" pipe size	Allow.	5,976	SF	0.00	10.00	0	59,800		0.25	1,494	1,718	INSL	45.09	77,500	137,300
41-33-65	Power connector and other accessories including thermostats for heat tracing (by zones)		Allow.	104	LS	0.00	950.00		98,500		8.00	829	953	WIRE	66.93	63,800	162,300
																	0
	Electrical - Auxiliary Power and Balance of Plant Electrical Work							**16,124,300**	**5,615,000**				**266,631**			**20,195,800**	**41,935,100**
41	Auxiliary Power Modifications	Quantities are total for Unit 1&2															
41-51-15	Rserve Aux. Transformer	230kV - 4.16kV, 34/45 MVA, 3phase	Est	1	EA	544,000.00	0.00	544,000	0		1,500	1,500	1,725	EHEA	67.88	117,100	661,100
41-51-15	Unit Aux. Transformers	24kV - 4.16kV, 15/20 MVA, 3 phase	Est	2	EA	490,000.00	0.00	980,000	0		1,200	2,400	2,760	EHEA	67.88	187,300	1,167,300
41-51-15	Transformer, 480 V Substation	4.16KV-480V,3phase, 2000/2666KVA	Est	4	EA	85,000.00	0.00	340,000	0		950.00	3,800	4,370	EHEA	67.88	296,600	636,600
41-51-15	Transformer, 480 V Substation	4.16KV-480V,3phase, 1500/2000KVA	Est	4	EA	77,000.00	0.00	308,000	0		950.00	3,800	4,370	EHEA	67.88	296,600	604,600

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
41-41-99	FGD/FF Power Control Centers (one for each unit)	(30'x60') building, includes: Enclosure with HVAC and Lighting/electric service 4160V swgr 480V swgr MCCs UPS Batteries / Chargers Room/Area designated for DCS Phone Jack	Est	2	EA	2,103,000.00	0.00	4,206,000	0		500.00	1,000	1,150	EHEA	67.88	78,100	4,284,100
23-17-23	Platforms around elevated PCC	quantities are total for Unit 1&2 PCCs	Est	2,850	SF	35.00	0.00	99,800	0		0.40	1,140	1,311	GALL	84.98	111,400	211,200
23-25-75	Support steel for PCC platforms		Est	20	TN	2,650.00	0.00	52,900	0		60.00	1,197	1,377	STST	105.69	145,500	198,400
41-41-99	UAT Power Control Centers (one for each unit).	(15'x20') building, includes: Enclosure with HVAC and Lighting/electric service 4160V swgr	Est	2	EA	300,000.00	0.00	600,000	0		200.00	400	460	EHEA	67.88	31,200	631,200
23-25-75	Auxiliary Steel Modifications for UAT PCC's to be located on turbine floor of each unit		Est	7	TN	2,650.00	0.00	18,600	0		60.00	420	483	STST	105.69	51,000	69,600
41-13-15	5KV Cable Bus duct	3000A	Est	14,700	FT	550.00	0.00	8,085,000	0		2.50	36,750	42,263	WIRE	85.64	3,619,400	11,704,400
23-25-75	Support steel for cable bus duct		Est	84	TN	0.00	2,650.00	0	222,600		16.00	1,344	1,546	STST	87.33	135,000	357,600
43-21-15	Cable Bus Terminations	750 KCM	Est	288	EA	0.00	100.00	0	28,800		3.00	864	994	WIRE	85.64	85,100	113,900
41-47-25	Relay Panels		Est	6	EA	40,000.00	0.00	240,000	0		120.00	720	828	WIRE	85.64	70,900	310,900
41-51-99	Lighting transformers 45KVA, 480V, 3 Phase	Low voltage XFMR	Est	16	EA	15,000.00	250.00	240,000	4,000		80.00	1,280	1,472	WIRE	85.64	126,100	370,100
41-47-15	Lighting Distribution panel, 200A, 208-120V, 3 Phase	Low voltage panel	Est	16	EA	10,000.00	200.00	160,000	3,200		60.00	960	1,104	WIRE	85.64	94,500	257,700
22-13-17	Duct Bank- Swgr Bldg to Truck Scale	24"x24", 4x4" cells (includes embedded conduit)	Est	2,100	LF	0.00	125	0	262,500		1.60	3,360	3,864	ECND	64.88	250,700	513,200
42-13-47	Cable Trays	36" Trays	Est	2,100	LF	0.00	30.00	0	63,000		1.00	2,100	2,415	ECND	64.88	156,700	219,700
42-13-47	Cable Trays	24" Control, & 24" Instrument	Est	2,100	LF	0.00	25.00	0			1.00	2,100	2,415	ECND	64.88	156,700	156,700
42-15-37	Conduits	misc sizes	Est	2,100	LF	0.00	10.00	0	21,000		0.35	735	845	ECND	64.88	54,800	75,800
	Miscellaneous Electrical System															0	
41-15-15	Cathodic Protection	Allowance	Allow.	2	LS	75,000.00	0.00	150,000	0		700.00	1,400	1,610	WIRE	85.64	137,900	287,900
41-25-55	Upgrade Fire detection system	Allowance	Allow.	2	LS	50,000.00	0.00	100,000	0		250.00	500	575	INEL	73.2	42,100	142,100
	CABLES																
43-21-15	Cables 5kV	3/C, 500 kcmil	Est	9,000	LF	0.00	29.11	0	262,000		0.69	6,210	7,142	WIRE	85.64	611,600	873,600
43-21-15	Cables 5kV	3/C, 250 kcmil	Est	1,050	LF	0.00	16.77	0	17,600		0.69	725	833	WIRE	85.64	71,400	89,000
43-21-15	Cables 5kV	3/C, #4/0	Est	6,300	LF	0.00	9.78	0	61,600		0.35	2,205	2,536	WIRE	85.64	217,200	278,800
43-21-35	Cables 5kV Terminations		Est	91	EA	0.00	50.00	0	4,600		1.25	114	131	WIRE	85.64	11,200	15,800
	480 V FGD Unit Substation FGD (SDA, Fabric Filter)																
43-17-15	Power Feeder Cable, 600 V, from Unit Sub FGD to MCCs	Power Feed to all MCC's (1/C 750 MCM)	Est	31,500	LF	0.00	9.82	0	309,300		0.18	5,670	6,521	WIRE	85.64	558,400	867,700
43-17-15	Power Cable, 600 V (to equipment)	3/C, #10	Est	21,000	LF	0.00	0.87	0	18,300		0.06	1,260	1,449	WIRE	85.64	124,100	142,400
43-17-15	Power Cable, 600 V (to equipment)	3/C, #6	Est	18,900	LF	0.00	1.92	0	36,300		0.10	1,890	2,174	WIRE	85.64	186,100	222,400

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
43-17-15	Power Cable, 600 V (to equipment)	3/C, #4	Est	7,770	LF	0.00	2.55	0	19,800		0.35	2,720	3,127	WIRE	85.64	267,800	287,600
43-17-15	Power Cable, 600 V (to equipment)	3/C, #2	Est	1,890	LF	0.00	4.40	0	8,300		0.35	662	761	WIRE	85.64	65,100	73,400
43-17-15	Power Cable, 600 V (to equipment)	3/C, #1/0	Est	2,100	LF	0.00	6.33	0	13,300		0.52	1,092	1,256	WIRE	85.64	107,500	120,800
43-17-15	Power Cable, 600 V (to equipment)	3/C, #4/0	Est	2,730	LF	0.00	13.35	0	36,400		0.52	1,420	1,633	WIRE	85.64	139,800	176,200
43-17-15	Power Cable, 600 V (to equipment)	3/C, 350KCMIL	Est	2,100	LF	0.00	17.98	0	37,800		0.69	1,449	1,666	WIRE	85.64	142,700	180,500
43-17-15	Power Cable, 600 V (to equipment)	3/C, 500KCMIL	Est	2,100	LF	0.00	26.41	0	55,500		0.69	1,449	1,666	WIRE	85.64	142,700	198,200
43-17-15	Power Cable, 600 V (for VFD's)	4/C, #10 SHLD	Est	2,100	LF	0.00	1.20	0	2,500		0.07	147	169	WIRE	85.64	14,500	17,000
43-17-15	Power Cable, 600 V (for VFD's)	4/C, #6 SHLD	Est	840	LF	0.00	2.70	0	2,300		0.10	84	97	WIRE	85.64	8,300	10,600
43-17-15	Power Cable, 600 V (for VFD's)	4/C, #4 SHLD	Est	630	LF	0.00	3.65	0	2,300		0.35	221	254	WIRE	85.64	21,700	24,000
43-17-15	Power Cable, 600 V (for VFD's)	3/C, 350KCMIL, SHLD	Est	2,100	LF	0.00	16.52	0	34,700		0.69	1,449	1,666	WIRE	85.64	142,700	177,400
43-13-17	Control Cable, 600 V	5/C, #10	Est	6,300	LF	0.00	1.30	0	8,200		0.08	504	580	WIRE	85.64	49,600	57,800
43-13-17	Control Cable, 600 V	2/C, #14	Est	31,500	LF	0.00	0.37	0	11,700		0.03	945	1,087	WIRE	85.64	93,100	104,800
43-13-17	Control Cable, 600 V	3/C, #14	Est	14,700	LF	0.00	0.42	0	6,200		0.03	441	507	WIRE	85.64	43,400	49,600
43-13-17	Control Cable, 600 V	5/C, #14	Est	6,300	LF	0.00	0.68	0	4,300		0.03	189	217	WIRE	85.64	18,600	22,900
43-13-17	Control Cable, 600 V	7/C, #14	Est	2,100	LF	0.00	0.95	0	2,000		0.04	84	97	WIRE	85.64	8,300	10,300
43-13-17	Control Cable, 600 V	9/C, #14	Est	2,100	LF	0.00	1.17	0	2,500		0.05	105	121	WIRE	85.64	10,300	12,800
43-17-35	Power & Control Cable Terminations	Power: 600, Control:1200	Est	3,780	EA	0.00	1.00	0	3,800		0.30	1,134	1,304	WIRE	85.64	111,700	115,500
43-13-13	Instrumentation Cable, 300 V	2 pr, #16 TW SHLD	Est	63,000	LF	0.00	0.32	0	20,200		0.03	2,016	2,318	WIRE	85.64	198,500	218,700
43-13-13	Instrumentation Cable, 300 V	2 tr, #16 TW SHLD	Est	14,700	LF	0.00	0.43	0	6,300		0.03	470	541	WIRE	85.64	46,300	52,600
43-13-13	Instrumentation Cable, 300 V	2 pr, #16 SHLD type E	Est	14,700	LF	0.00	0.35	0	5,100		0.03	470	541	WIRE	85.64	46,300	51,400
43-13-33	Fiber Optic Cable	2 strand	Est	2,100	LF	0.00	0.50	0	1,100		0.03	63	72	WIRE	85.64	6,200	7,300
43-13-33	Fiber Optic Cable	6 strand	Est	5,250	LF	0.00	0.96	0	5,000		0.03	158	181	WIRE	85.64	15,500	20,500
43-13-33	Fiber Optic Cable	12 strand	Est	1,260	LF	0.00	1.46	0	1,800		0.03	38	43	WIRE	85.64	3,700	5,500
43-13-33	Fiber Optic Cable	24 strand	Est	2,730	LF	0.00	2.21	0	6,000		0.05	137	157	WIRE	85.64	13,400	19,400
43-13-99	Profibus DP Cable		Est	8,400	LF	0.00	1.50	0	12,600		0.05	420	483	WIRE	85.64	41,400	54,000
43-13-27	Cat 5E		Est	3,150	LF	0.00	1.40	0	4,400		0.05	158	181	WIRE	85.64	15,500	19,900
43-13-43	Instrumentation Cable Terminations		Est	6,300	EA	0.00	1.00	0	6,300		0.25	1,575	1,811	WIRE	85.64	155,100	161,400
42-17-15	Misc. Junction Boxes & Pull Boxes		Est	2	LT	0.00	154,000.00	0	308,000		900.00	1,800	2,070	WIRE	85.64	177,300	485,300
42-13-47	Cable Trays	36" Trays	Est	8,400	LF	0.00	30.00	0	252,000		1.00	8,400	9,660	ECND	64.88	626,700	878,700
42-13-47	Cable Trays	24" Control, & 24" Instrument	Est	12,600	LF	0.00	25.00	0			1.00	12,600	14,490	ECND	64.88	940,100	940,100
42-15-37	Conduits	misc sizes	Est	73,500	LF	0.00	10.00	0	735,000		0.35	25,725	29,584	ECND	64.88	1,919,400	2,654,400
41-31-15	Grounding	Includes ground grid, rods, bolted connections & cadwelds. Future installation only	Est	2	LT	0.00	50,000.00	0	100,000		800.00	1,600	1,840	WIRE	85.64	157,600	257,600
41-17-25	PA / Page Party Extension System		Allow.	2	LT	0.00	20,000.00	0	40,000		300.00	600	690	WIRE	85.64	59,100	99,100
41-17-35	Data COM Extension System		Allow.	2	LT	0.00	5,000.00	0	10,000		120.00	240	276	WIRE	85.64	23,600	33,600
41-17-35	Telephone Extension System		Allow.	2	LT	0.00	5,000.00	0	10,000		140.00	280	322	WIRE	85.64	27,600	37,600
41-53-17	Security System		Allow.	2	LT	0.00	100,000.00	0	200,000		600.00	1,200	1,380	WIRE	85.64	118,200	318,200
	480 V Lime/Ash Handling Unit Sub (Lime Handling, Reagent Prep, Ash Handl Area)																
43-17-15	Power Cable, 600 V (to equipment)	3/C, #10	Est	18,900	LF	0.00	0.87	0	16,400		0.06	1,134	1,304	WIRE	85.64	111,700	128,100
43-17-15	Power Cable, 600 V (to equipment)	3/C, #6	Est	18,900	LF	0.00	1.92	0	36,300		0.10	1,890	2,174	WIRE	85.64	186,100	222,400
43-17-15	Power Cable, 600 V (to equipment)	3/C, #4	Est	6,300	LF	0.00	2.55	0	16,100		0.35	2,205	2,536	WIRE	85.64	217,200	233,300
43-17-15	Power Cable, 600 V (to equipment)	3/C, #1/0	Est	2,100	LF	0.00	6.33	0	13,300		0.52	1,092	1,256	WIRE	85.64	107,500	120,800
43-17-15	Power Cable, 600 V (to equipment)	3/C, #4/0	Est	2,310	LF	0.00	11.53	0	26,600		0.52	1,201	1,381	WIRE	85.64	118,300	144,900
43-17-15	Power Cable, 600 V (to equipment)	3/C, 350KCMIL	Est	2,100	LF	0.00	17.98	0	37,800		0.69	1,449	1,666	WIRE	85.64	142,700	180,500
43-17-15	Power Cable, 600 V (to equipment)	3/C, 500KCMIL	Est	6,300	LF	0.00	26.41	0	166,400		0.69	4,347	4,999	WIRE	85.64	428,100	594,500
43-17-15	Power Cable, 600 V	4/C, #10 SHLD	Est	2,100	LF	0.00	1.20	0	2,500		0.07	147	169	WIRE	85.64	14,500	17,000
43-17-15	Power Cable, 600 V	4/C, #6 SHLD	Est	1,260	LF	0.00	2.70	0	3,400		0.10	126	145	WIRE	85.64	12,400	15,800
43-17-15	Power Cable, 600 V	3/C, 350KCMIL, SHLD	Est	1,260	LF	0.00	17.98	0	22,700		0.69	869	1,000	WIRE	85.64	85,600	108,300
43-17-15	Control Cable, 600 V	2/C, #10	Est	12,600	LF	0.00	0.70	0	8,800		0.03	378	435	WIRE	85.64	37,200	46,000
43-17-15	Control Cable, 600 V	7/C, #10	Est	5,250	LF	0.00	1.60	0	8,400		0.12	630	725	WIRE	85.64	62,000	70,400
43-17-15	Control Cable, 600 V	2/C, #14	Est	29,400	LF	0.00	0.37	0	10,900		0.03	882	1,014	WIRE	85.64	86,900	97,800
43-17-15	Control Cable, 600 V	3/C, #14	Est	10,500	LF	0.00	0.42	0	4,400		0.03	315	362	WIRE	85.64	31,000	35,400
43-17-15	Control Cable, 600 V	5/C, #14	Est	9,450	LF	0.00	0.68	0	6,400		0.03	284	326	WIRE	85.64	27,900	34,300
43-17-15	Control Cable, 600 V	7/C, #14	Est	2,100	LF	0.00	0.95	0	2,000		0.04	84	97	WIRE	85.64	8,300	10,300
43-17-35	Power & Control Cable Terminations	Power: 510, Control: 1000	Est	3,171	EA	0.00	1.00	0	3,200		0.30	951	1,094	WIRE	85.64	93,700	96,900
43-13-13	Instrumentation Cable, 300 V	1 pr, #16 TW SHLD	Est	10,500	LF	0.00	0.18	0	1,900		0.03	315	362	WIRE	85.64	31,000	32,900
43-13-13	Instrumentation Cable, 300 V	1 tr, #16 TW SHLD	Est	2,100	LF	0.00	0.29	0	600		0.03	63	72	WIRE	85.64	6,200	6,800
43-13-13	Instrumentation Cable, 300 V	2 pr, #16 TW SHLD	Est	21,000	LF	0.00	0.32	0	6,700		0.03	630	725	WIRE	85.64	62,000	68,700
43-13-13	Instrumentation Cable, 300 V	2 tr, #16 TW SHLD	Est	4,200	LF	0.00	0.43	0	1,800		0.03	126	145	WIRE	85.64	12,400	14,200
43-13-13	Instrumentation Cable, 300 V	8 pr, #16 TW SHLD	Est	4,200	LF	0.00	0.86	0	3,600		0.10	420	483	WIRE	85.64	41,400	45,000
43-13-13	Instrumentation Cable, 300 V	2 pr, #16 SHLD type E	Est	12,600	LF	0.00	0.35	0	4,400		0.03	403	464	WIRE	85.64	39,700	44,100
43-13-33	Fiber Optic Cable	2 strand	Est	2,100	LF	0.00	0.50	0	1,100		0.03	63	72	WIRE	85.64	6,200	7,300
43-13-33	Fiber Optic Cable	6 strand	Est	5,250	LF	0.00	0.96	0	5,000		0.03	158	181	WIRE	85.64	15,500	20,500
43-13-33	Fiber Optic Cable	12 strand	Est	1,260	LF	0.00	1.46	0	1,800		0.03	38	43	WIRE	85.64	3,700	5,500

								OG & E								Estimate No.:	30228 A1
								Sooner Units 1 & 2								Project No.:	11418-019
								Dry FGD Systems								Date:	12/11/2009
								Conceptual Cost Estimate								Prepared by:	MNO
		Cost Type:														Reviewed by:	RK
		Est=Estimated														Approved by:	PEF
		Allow.=Allowance									Wage Rates Based on:				9NUR06		
		C= Contract									Labor Productivity =				1.15		
		Q=Vendor Quote															
Code of Accounts	**Item Description**	**Scope Definition**	**Cost Type**	**Quantity**	**Unit of Measure**	**Unit Equip.Cost**	**Unit Material Cost**	**Total Equipment Cost**	**Total Material Cost**	**Cost Development**	**Unit Man-hours (Base)**	**Total Man hours (Base)**	**Total Man-hours, Prod = 1.15**	**Crew Code**	**Crew Wage Rate**	**Total Construction & Erection Cost**	**Total Projected Cost**
43-13-33	Fiber Optic Cable	24 strand	Est	2,730	LF	0.00	2.21	0	6,000		0.05	137	157	WIRE	85.64	13,400	19,400
43-13-99	Profibus DP Cable		Est	8,400	LF	0.00	1.50	0	12,600		0.05	420	483	WIRE	85.64	41,400	54,000
43-13-27	Cat 5E		Est	3,150	LF	0.00	1.40	0	4,400		0.05	158	181	WIRE	85.64	15,500	19,900
43-13-43	Instrumentation Cable Terminations		Est	6,300	EA	0.00	1.00	0	6,300		0.25	1,575	1,811	WIRE	85.64	155,100	161,400
42-17-15	Misc. Junction Boxes & Pull Boxes		Est	2	LT	0.00	100,000.00	0	200,000		600.00	1,200	1,380	WIRE	85.64	118,200	318,200
42-13-47	Cable Trays	36" Trays	Est	8,400	LF	0.00	30.00	0	252,000		1.00	8,400	9,660	ECND	64.88	626,700	878,700
42-13-47	Cable Trays	24" Control, & 24" Instrument	Est	12,600	LF	0.00	25.00	0	315,000		1.00	12,600	14,490	ECND	64.88	940,100	1,255,100
42-15-37	Conduits	misc sizes	Est	52,500	LF	0.00	10.00	0	525,000		0.35	18,375	21,131	ECND	64.88	1,371,000	1,896,000
41-31-15	Grounding	Includes ground grid, rods, bolted connections & cadwelds. Future installation only	Est	2	LT	0.00	50,000.00	0	100,000		800.00	1,600	1,840	WIRE	85.64	157,600	257,600
41-17-25	PA / Page Party Extension System		Est	2	LT	0.00	20,000.00	0	40,000		300.00	600	690	WIRE	85.64	59,100	99,100
41-17-35	Data COM Extension System		Est	2	LT	0.00	5,000.00	0	10,000		120.00	240	276	WIRE	85.64	23,600	33,600
41-17-35	Telephone Extension System		Est	2	LT	0.00	5,000.00	0	10,000		140.00	280	322	WIRE	85.64	27,600	37,600
41-53-17	Lightning Protection		Est	2	LT	0.00	30,000.00	0	60,000		300.00	600	690	WIRE	85.64	59,100	119,100
	Electrical Aux Power Structural Work							**0**									
	Foundations for FGD/FF PCC's	Quantities shown are total for 2 buildings, 1/unit															
21-23-15	Excavation		Est	963	CY	0.00	0.00	0	0		0.20	193	221	EXFD	63.95	14,200	14,200
21-17-25	Backfill		Est	63	CY	0.00	0.00	0	0		0.30	19	22	EXFD	63.95	1,400	1,400
22-13-37	Concrete		Est	900	CY	0.00	105.00	0	94,500		1.50	1,350	1,553	CONP	51.69	80,200	174,700
22-25-35	Reinforcing		Est	68	TN	0.00	1,150.00	0	77,600		20.00	1,350	1,553	REIN	61.48	95,400	173,000
22-17-25	Formwork		Est	3,600	SF	0.00	2.50	0	9,000		0.14	486	559	FORM	71.62	40,000	49,000
22-15-25	Embedded Steel		Est	7,200	LB	0.00	2.50	0	18,000		0.05	360	414	CARP	46.37	19,200	37,200
22-13-67	Transformer Firewalls	2700 SF	Est	100	CY	0.00	225.00	0	22,500		12.00	1,200	1,380	CONP	74.7	103,100	125,600
	Transformer Foundations	Total for UAT and RAT with containments						0	0								0
21-23-15	Excavation		Est	621	CY	0.00	0.00	0	0		0.20	124	143	EXFD	81.96	11,700	11,700
21-17-25	Backfill		Est	41	CY				0		0.30	12	14	EXFD	81.96	1,100	1,100
22-13-37	Concrete		Est	580	CY	0.00	105.00	0	60,900		1.50	870	1,001	CONP	74.7	74,700	135,600
22-25-35	Reinforcing		Est	44	TN	0.00	1,150.00	0	50,000		20.00	870	1,001	REIN	79.19	79,200	129,200
22-17-25	Formwork		Est	2,320	SF	0.00	2.50	0	5,800		0.14	313	360	FORM	90.9	32,700	38,500
22-15-25	Embedded Steel		Est	2,900	LB	0.00	2.50	0	7,300		0.06	174	200	CARP	64.41	12,900	20,200
23-25-75	Structural Steel	Basin Gallery Steel for containments		4.50	TN	0.00	2,650.00	0	11,900		25.00	113	129	STST	105.69	13,700	25,600
23-17-23	1 1/4" Grating (Galv)	Basin Grating		750	SF	0.00	18.00	0	13,500		0.20	150	173	GALL	84.98	14,700	28,200
	Controls & Instrumentation							**4,125,000**	**75,000**				**16,388**			**888,500**	**5,088,500**
44-13-15	DCS	4500 I/O points	Est	1	LS	2,925,000.00	0.00	2,925,000	0		6,750	6,750	7,763	INEL	54.22	420,900	3,345,900
71-55-45	DCS - Vendor Field Support	200 mandays @ $1500/day	Est	200	DAYS	1,500.00	0.00	300,000	0		0.00	0	0	INEL	54.22	0	300,000
44-24-43	Locally Mounted Instruments		Est	300	EA	3,000.00	0.00	900,000	0		20	6,000	6,900	INEL	54.22	374,100	1,274,100
44-17-15	Instrument Racks	included with instruments															
35-15-13	Instrument Tubing		Allow	1	LT	0.00	75,000	0	75,000		1,500	1,500	1,725	INEL	54.22	93,500	168,500
	Modifications / Installation of CEM system	Not required	Est														
	Civil Work							**0**	**1,482,700**				**26,717**			**2,114,700**	**3,597,400**
21	**Laydown Area**	Approx 4 Acre															
21-13-25	Cut and strip	Topsoil stripping	Est	38720	CY	0.00	0.00	0	0	0.010	0.030	1,162	1,336	ETWK	152.54	203,800	203,800
21-13-45	Topsoil storage stockpile	assumes on site stockpiling	Est	38720	CY	0.00	0.00	0	0	0.010	0.010	387	445	ETWK	152.54	67,900	67,900
21-51-27	Geotextile membrane	10 oz/sy	Est	19360	SY	0.00	1.80	0	34,800	0.010	0.010	194	223	LAND	30.15	6,700	41,500
21-57-55	Aggregate surfacing	4" thick over entire area	Est	19360	SY	0.00	5.65	0	109,400	0.010	0.020	387	445	BCSE	82.08	36,500	145,900
21-47-25	Grass seeding over stockplie area		Est	4	ACRE	0.00	1,000	0	4,000	0.010	60	240	276	LAND	30.15	8,300	12,300
21-41-65	Silt Fence	Total for stockplie and laydown area	Est	1,820	LF	0.00	1	0	1,800		0.02	36	42	LAND	30.15	1,300	3,100
21-43-25	Fencing with one 3-strand barbed wire unit	Fabric, posts on 10ft centers	Est	1,760	LF	0.00	40	0	70,400		0.28	493	567	LAND	30.15	17,100	87,500
21-43-45	Gates	50ft wide double swing	Est	2	EA	0.00	3,500.00	0	7,000		40	80	92	LAND	30.15	2,800	9,800
21	**Restoration of Laydown Area**		Est	0	ACRE	0.00	15.00	0	0		35	0	0	ETWK	152.54	0	0
21-21-25	Remove and dispose of aggregate		Est	2,215	CY	0.00	0.00	0	0	0.010	0.007	16	18	BCSE	82.08	1,500	1,500
11-21-99	Removal of Geotextile membrane		Est	19360	SY	0.00	0.00	0	0	0.010	0.003	58	67	LAND	30.15	2,000	2,000
21-23-15	Earthwork to restore - Cut		Est	2,462	CY	0.00	0.00	0	0	0.010	0.030	74	85	EXFD	63.95	5,400	5,400
21-23-45	Earthwork to restore - Fill		Est	2,462	CY	0.00	0.00	0	0	0.010	0.050	123	142	EXFD	63.95	9,100	9,100
21-23-45	Place topsoil - previously stockpiled		Est	70000	CY	0.00	0.00	0	0	0.010	0.050	3,500	4,025	EXFD	63.95	257,400	257,400
21-47-25	Grass seeding - mulch and fertilizer		Est	4	ACRE	0.00	1,500	0	6,000	0.010	90	360	414	LAND	30.15	12,500	18,500
21	**DFGD Area**	Approx 4 Acre															
21-13-25	Cut and strip	Topsoil stripping	Est	43560	CY	0.00	0.00	0	0	0.010	0.030	1,307	1,503	ETWK	152.54	229,200	229,200
21-13-45	Topsoil storage stockpile	assumes on site stockpiling	Est	43560	CY	0.00	0.00	0	0	0.010	0.010	436	501	ETWK	152.54	76,400	76,400
21-51-27	Geotextile membrane	10 oz/sy	Est	21780	SY	0.00	1.80	0	39,200	0.010	0.010	218	250	LAND	30.15	7,600	46,800

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
21-57-55	Aggregate surfacing	4" thick over entire area	Est	24200	SY	0.00	5.65	0	136,700	0.010	0.020	484	557	BCSE	82.08	45,700	182,400
	Plant Drainage																
21-25-15	Excavation		Est	600	CY	0.00	0.00	0	0	0.010	0.200	120	138	EXFD	63.95	8,800	8,800
21-57-55	Crushed rock surfacing	12"	Est	240	CY	0.00	54.00	0	13,000		0.14	34	39	BCSE	82.08	3,200	16,200
	Storm Sewer																
22-23-65	4ft Manholes		Est	6	EA	0.00	1,575.00	0	9,500		20.00	120	138	YDPP	63.15	8,700	18,200
22-23-65	6ft Manholes		Est	5	EA	0.00	3,000.00	0	15,000		30.00	150	173	YDPP	63.15	10,900	25,900
22-23-65	24"x24" Catch Basin	3 ft deep	Est	10	EA	0.00	500.00	0	5,000		6.00	60	69	YDPP	63.15	4,400	9,400
35-13-35	18" CHDPE		Est	750	LF	0.00	30.00	0	22,500		0.30	225	259	YDPP	63.15	16,300	38,800
35-13-35	24" CHDPE		Est	750	LF	0.00	40.00	0	30,000		0.40	300	345	YDPP	63.15	21,800	51,800
35-13-35	36" CHDPE		Est	750	LF	0.00	70.00	0	52,500		0.65	488	561	YDPP	63.15	35,400	87,900
21	**Oily Water Sewer System**																
22-23-65	4ft Manholes		Est	7	EA	0.00	1,575.00	0	11,000		20.00	140	161	YDPP	63.15	10,200	21,200
35-13-23	6" CISP		Est	1,650	LF	0.00	28.00	0	46,200		1.05	1,733	1,992	YDPP	63.15	125,800	172,000
35-13-23	6" Post indicator valve		Est	6	EA	0.00	450.00	0	2,700		6.00	36	41	YDPP	63.15	2,600	5,300
31-93-53	Oil Water Separator with Lift Station	3,000 gal	Est	1	EA	0.00	100,000.00	0	100,000		1130.00	1,130	1,300	YDPP	63.15	82,100	182,100
21	**Sanitary Sewer**																
22-23-65	4ft Manholes		Est	7	EA	0.00	1,575.00	0	11,000		20.00	140	161	YDPP	63.15	10,200	21,200
22-23-65	Cleanouts		Est	5	EA	0.00	690.00	0	3,500		8.00	40	46	YDPP	63.15	2,900	6,400
35-13-23	6" CISP		Est	1,600	LF	0.00	28.00	0	44,800		1.05	1,680	1,932	YDPP	63.15	122,000	166,800
21-25-15	Excavation	for all drainage and sewer piping	Est	2,222	CY	0.00	0.00	0	0	0.010	0.200	444	511	EXFD	63.95	32,700	32,700
21-17-15	Bedding / backfill	for all drainage and sewer piping	Est	556	CY	0.00	40.00	0	22,200	0.010	0.300	167	192	EXFD	63.95	12,300	34,500
	Interior Plant Roads and Surfacing																
21-13-25	Cut and strip	Topsoil stripping	Est	2,889	CY	0.00	0.00	0	0	0.010	0.030	87	100	ETWK	152.54	15,200	15,200
21-13-25	Cut		Est	722	CY	0.00	0.00	0	0	0.010	0.030	22	25	ETWK	152.54	3,800	3,800
21-17-55	Fill		Est	722	CY	0.00	0.00	0	0	0.010	0.050	36	42	ETWK	152.54	6,300	6,300
21-51-27	Geotextile membrane	10 oz/sy	Est	8,667	SY	0.00	1.80	0	15,600	0.010	0.010	87	100	LAND	30.15	3,000	18,600
21-57-55	Aggregate surfacing	6" thick over entire area	Est	8,667	SY	0.00	8.50	0	73,700	0.010	0.020	173	199	BCSE	82.08	16,400	90,100
21-57-35	Concrete road	9" thick, 24ft W x 2600 L	Est	1,733	CY	0.00	17.52	0	30,400		0.29	503	578	PBIT	64.44	37,300	67,700
22-25-35	Reinforcing		Est	173	TN	0.00	1,150.00	0	199,300		20.00	3,467	3,987	REIN	79.19	315,700	515,000
22-17-25	Formwork		Est	5,200	SF	0.00	2.50	0	13,000		0.14	702	807	FORM	90.9	73,400	86,400
21-57-55	Contractor Trailer Area Surfacing	Includes: 9" aggregate surfacing 12" subgrade prep	Est	14520	SY	0.00	22.48	0	326,400		0.10	1,452	1,670	BCSE	82.08	137,100	463,500
21-51-27	Geotextile membrane - entire area	10 oz/sy	Est	14520	SY	0.00	1.80	0	26,100	0.010	0.010	145	167	LAND	30.15	5,000	31,100
	Removal and Relocation of Existing Equipment and Infrastructure							**0**	**859,300**				**16,890**			**1,188,300**	**2,047,600**
	Miscellaneous Pipe Relocation - Underground	Quantities are total for Units 1&2															
35-13-15	14" CS, SCH 40, includes fittings	Fuel oil and chemical drains	Est	938	LF	0.00	259.50	0	243,400		2.94	2,758	3,171	YDPP	63.15	200,300	443,700
35-13-15	12" CS, SCH 40, includes fittings	Chemical drains and service water	Est	375	LF	0.00	246.30	0	92,400		2.88	1,080	1,242	YDPP	63.15	78,400	170,800
35-13-15	8" CS, SCH 40, includes fittings	Oil drains	Est	375	LF	0.00	89.50	0	33,600		1.60	600	690	YDPP	63.15	43,600	77,200
35-13-15	6" CS, SCH 40, includes fittings	Fuel oil and service water	Est	563	LF	0.00	130.20	0	73,300		1.88	1,058	1,217	YDPP	63.15	76,900	150,200
21-25-15	Excavation for Underground Piping		Est	834	CY	0.00	0.00	0	0		0.20	167	192	EXFD	63.95	12,300	12,300
21-17-15	Bedding for Underground Piping		Est	125	CY	0.00	40.00	0	5,000		0.30	38	43	EXFD	63.95	2,800	7,800
21-17-25	Backfill for Underground Piping		Est	709	CY	0.00	0.00	0	0		0.30	213	244	EXFD	63.95	15,600	15,600
	Miscellaneous Pipe Relocation - Above Ground	Quantities are total for Units 1&2	Allow.	1	LT	0.00	200,000	0	200,000		3000.00	3,000	3,450	WIRE	66.93	230,900	430,900
35-13-15	12" CS, SCH 40, includes fittings	Ash water, Unit 1&2	Est	250	LF	0.00	246.30	0	61,600		2.88	720	828	YDPP	63.15	52,300	113,900
35-13-15	10" CS, SCH 40, includes fittings	Ash water	Est	250	LF	0.00	196.80	0	49,200		2.32	580	667	YDPP	63.15	42,100	91,300
35-13-15	8" Ashcolite, flanged	Ash sluice line	Est	500	LF	0.00	145.20	0	72,600		1.54	770	886	YDPP	63.15	55,900	128,500
35-13-15	4" CS, SCH 40, includes fittings	Service water	Est	250	LF	0.00	57.60	0	14,400		1.50	375	431	YDPP	63.15	27,200	41,600
35-13-33	Pipe Supports for relocated piping		Est	5.22	TN	0.00	2,650.00	0	13,800		40.00	209	240	STST	87.33	21,000	34,800
	Miscellaneous Structures Building Demolition	Unit 1															
11-26-99	Ductwork		Est	120	TN	0.00	0	0	0		15.00	1,800	2,070	WRKG	91.68	189,800	189,800
11-23-99	Steel		Est	25	TN	0.00	0	0	0		12.00	300	345	WRKG	91.68	31,600	31,600
11-22-99	Concrete	Assumed existing foundations to be left in place															
	Miscellaneous Structures Building Demolition	Unit 2															

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
11-26-99	Ductwork		Est	60	TN	0.00	0	0	0		15.00	900	1,035	WRKG	91.68	94,900	94,900
11-23-99	Steel		Est	10	TN	0.00	0	0	0		12.00	120	138	WRKG	91.68	12,700	12,700
11-22-99	Concrete	Assumed existing foundations to be left in place															
	Sub-Total of Equipment Material and Labor Costs							**113,383,200**	**38,719,000**				**1,647,446**			**109,453,400**	**261,555,600**
	Other Costs																**61,016,900**
81-13-45	Additional Crane Rental Allowance			4.00	%				0							4,378,136	4,378,136
61-27-25	Mobilization/Demobilization		Est	2.00	%											2,189,068	2,189,100
61-23-35	Scaffolding		Est	2.50	%				967,975							2,736,335	3,704,300
61-17-43	Temporary Facilities and Construction Utilities (Elect, Water, etc.) During Construction			1.00	%				0							1,094,534	1,094,500
	Allowance for Premium Time Labor Five (5) days per week Ten (10) hours per day.		Est	1	LS												0
61-21-45	Cost due to overtime inefficiency working 5x10's			8.00	%								143,256		66	9,518,000	9,518,000
61-21-65	Per Diem Expense @ $10/HR			10	hr											17,907,025	17,907,000
91-13-15	BOP Contractor's General & Administrative Costs	Based on BOP Materials & Labor Costs at 5% (not incl. Equipment Costs)	Est	5.00	%				1,935,950							5,472,670	7,408,600
91-15-25	BOP Contractor's Profit	Based on BOP Materials & Labor Costs at 10% (not incl. Equipment Costs)	Est	10.00	%				3,871,900							10,945,340	14,817,240
	Total Equipment, Material and Labor Costs							**113,383,200**	**45,494,800**				**1,790,700**			**163,694,500**	**322,572,500**
	Spare Parts, Special Tools and Consumables																**794,000**
81-27-75	Mandatory Spare Parts (first year of operation)			0.00	%			0								0	0
81-25-35	Special Tools																Included w\Equipment Costs
81-25-25	Consumables (0.5% of Equipment/Material Cost)			0.5	%			567,000	227,000								794,000
	Freight, Duties, Taxes, Etc.																**1,936,000**
71-27-35	Freight-ExWorks To Site	For material costs only. Freight for Equipment included with equipment costs.		5	%				1,935,950								1,936,000
71-47-45	Taxes - Sales/Use/VAT/Business/Etc.	Not Included															0
	Total Direct Costs							**113,950,200**	**47,657,800**							**163,694,500**	**325,302,500**
	Total Indirect Costs							0	0								**48,090,100**
71-13-15	Engineering / Procurement			6.50	%											21,144,700	21,144,700
71-23-15	Construction Management			2.00	%											6,506,100	6,506,100
71-45-57	Start-up & Commissioning Craft Support			2.00	%											3,273,900	3,273,900
71-53-15	Operator Training & Manuals			0.55	%											900,300	900,300
71-21-15	Owner's Cost			5.00	%											16,265,125	16,265,125

OG & E
Sooner Units 1 & 2
Dry FGD Systems
Conceptual Cost Estimate

Estimate No.: 30228 A1
Project No.: 11418-019
Date: 12/11/2009
Prepared by: MNO
Reviewed by: RK
Approved by: PEF

Cost Type:
Est=Estimated
Allow.=Allowance
C= Contract
Q=Vendor Quote

Wage Rates Based on: 9NUR06
Labor Productivity = 1.15

Code of Accounts	Item Description	Scope Definition	Cost Type	Quantity	Unit of Measure	Unit Equip.Cost	Unit Material Cost	Total Equipment Cost	Total Material Cost	Cost Development	Unit Man-hours (Base)	Total Man-hours (Base)	Total Man-hours, Prod = 1.15	Crew Code	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
	Total Project Cost without Escalation / Contingency																**373,392,600**
95-95-95	**Escalation**																**46,602,900**
	Equipment.00%							11,964,800									11,964,800
	Material.00%								5,718,900								5,718,900
	Labor.00%															23,244,600	23,244,600
	Indirects.00%															5,674,600	5,674,600
93-93-93	**Contingency**			13.970	%												**58,673,400**
	Total Project Cost with Escalation / Contingency																**478,668,900**
97-97-97	**Bond Cost**			1.00	%												**4,786,700**
97-97-97	**Interest During Construction (AFUDC)**			8.66	%												**101,133,800**
	Total Project Cost																**584,589,400**

OG+E

SOONER UNITS 1&2
MUSKOGEE UNITS 4 & 5

DRY FGD
DESIGN AND COST ESTIMATE BASIS DOCUMENT

DECEMBER 11, 2009

PROJECT 11418-019

PREPARED BY

Sargent & Lundy LLC

CONTENTS

SECTION PAGE

CONTENTS

SECTION **PAGE**

Tables

Attachments

1. SOONER PLANT LOCATION AND TRANSPORTATION ACCESS

Sooner Station consists of two 575 MW pulverized coal fired units located east of Red Rock, Oklahoma. Sooner Station is located on 11,000 acres of land that straddles Noble and Pawnee Counties. The power block for Sooner 1 & 2 is located in Noble County.

The site is served by the Burlington Northern Santa Fe Railroad. The site is also accessible via truck from US Highway 177.

A major feature of the site is the 150,000 acre-foot reservoir that provides cooling water for Sooner 1 & 2.

The northern portion of the site contains the coal storage area. The rail loop encircles the coal handling area. Coal pile runoff flows to the Coal Pile Runoff Pond which, in turn, flows to the Waste System Evaporation Pond.

Sooner 1 & 2 began commercial operation in 1979 and 1980 respectively. Sooner 1 & 2 are currently base load units and use No. 2 fuel oil as a start-up fuel and sub-bituminous low sulfur coal as the primary fuel. Each boiler was manufactured by Combustion Engineering with a design output of 550 megawatts (MW). Particulate emissions are controlled by cold side electrostatic dust precipitators with a design removal efficiency of 99.52%. Both units have 500-foot tall chimneys.

1.1 WEATHER CONDITIONS

1.1.1 Sooner Plant Weather Conditions

Table 1.1-1 lists the major site conditions at Sooner Station, which are based on American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE) data.

Table 1.1-1
Major Site Conditions – Sooner Station

Parameter	Data
Nearest weather data location (2009 ASHRAE Handbook – Fundamentals (IP))	Stillwater, OK Regional Airport
Latitude/longitude	36.15N/97.08W
Elevation	933 feet
Standard pressure	14.07 psia
Heating dry bulb temperature, 99.6% occurrence	13.6 °F

Parameter	Data
Cooling dry bulb temperature, 0.4% occurrence	101.8 °F
Extreme wind speed, 1% occurrence	24.6 mph
50-year occurrence dry bulb temperatures:	
Maximum	112.3 °F
Minimum	-10.3 °F

1.1.2 Muskogee Plant Weather Conditions

Table 1.1-2 lists the major site conditions at Muskogee Station which are based on American Society of Heating, Refrigeration and Air Conditioning Engineers (ASHRAE) data.

Table 1.1-2
Major Site Conditions – Muskogee Station

Parameter	Data
Nearest weather data location (2009 ASHRAE Handbook – Fundamentals (IP))	Tulsa, OK Lloyd Jones Regional Airport
Latitude/longitude	35.40N/97.58W
Elevation	520 feet
Standard pressure	14.42 psia
Heating dry bulb temperature, 99.6% occurrence	15.8 °F
Cooling dry bulb temperature, 0.4% occurrence	100.1 °F
Extreme wind speed, 1% occurrence	19.8 mph
50-year occurrence dry bulb temperatures:	
Maximum	112.3 °F
Minimum	-10.3 °F

2. FUEL CHARACTERISTICS

2.1 MAIN FUEL

Each facility typically fires Powder River Basin (PRB) coal delivered to each site by rail.

The design basis fuel analysis, presented in Table 2.1-1 was developed based on the PRB coal fired at the stations and potential future PRB coal sources. The worst case coal was used to size the FGD equipment while the average coal was used to develop yearly O&M costs.

Table 2.1-1: Sooner & Muskogee – Coal Properties

FUEL ANALYSIS:		Powder River Basin Worst Case PRB (FGD Sizing)	Powder River Basin Average PRB (Used for O&M Costs)
Ultimate Analysis		-	-
Carbon	%	48.52	51.29
Sulfur	**%**	**0.48**	**0.22**
Oxygen	%	11.80	12.22
Hydrogen	%	3.10	3.34
Nitrogen	%	0.77	0.67
Chlorine	%	0.01	0.01
Ash	%	7.50	5.30
Moisture	%	27.82	26.95
		100.00	100.00
Proximate Analysis			
Moisture	%	27.8	26.95
Volatile matter	%	32.21	31.73
Fixed Carbon	%	32.47	36.04
Ash	%	7.50	5.30
Gross (Higher) Heating Value	Btu/lb	8,000	8,400
Gross Heating Value (Dulong)	Btu/lb	8,084	8,593
Hardgrove Grindability	HGI	59	59
Chlorine	ppmvd (wt)	125	100
Fluorine	ppmvd (wt)	75	60
Mercury	ppmvd (wt)	0.10	0.08
Ash Analysis			
Silica	%	32.00	36.64
Ferric Oxide	%	5.00	5.57
Alumina	%	16.00	16.06
Titanic Oxide	%	1.30	1.37
Calcium Oxide	%	22.50	22.04
Magnesia	%	4.80	4.89

FUEL ANALYSIS:		Powder River Basin Worst Case PRB (FGD Sizing)	Powder River Basin Average PRB (Used for O&M Costs)
Sulfur Trioxide	%	14.70	8.40
Potassium Oxide	%	0.40	0.46
Sodium Oxide	%	1.10	1.64
Phosphorous Pentoxide	%	1.10	0.84
Barium Oxide	%	0.00	0.52
Undetermined	%	1.13	1.57
Total	%	100.0	100.0

3. WATER SUPPLY

Each station will supply water for the dry FGD system from its existing cooling water supply. Because dry FGD systems do not produce wastewater, additional wastewater treatment is not required at either site.

3.1 SOONER STATION RAW WATER SUPPLY

Sooner Station utilizes a cooling water reservoir to supply water to its once-through cooling system. The dry FGD will draw raw water from this same reservoir to use in its process. New raw water pumps will be installed near the existing circulating water pumps to supply make-up water to the dry FGD system.

3.2 MUSKOGEE STATION RAW WATER SUPPLY

Muskogee Station draws makeup water for its cooling towers from the Arkansas River. The Dry FGD will also draw raw water from the Arkansas River to use in its process.

4. AIR QUALITY CONTROL SYSTEMS (AQCS)

4.1 SO_2 EMISSIONS CONTROL

Emissions of SO_2 will be controlled using DFGD systems at both stations. Pebble lime slurry and recycle ash slurry will be used as the reagents. The maximum lime usage will be based on pebble lime with at least 90 percent as CaO availability determined using ASTM C25 and at least 40° C temperature rise in 3 minutes reactivity determined using ASTM C110.

4.2 PARTICULATE EMISSIONS CONTROL

Each of Sooner Units 1 and 2 and Muskogee Units 4 and 5 have existing electrostatic precipitators (ESPs) to control particulate emissions. These ESPs will remain in service after the DFGD systems are installed to allow both plants to continue to sell their ESP fly ash.

Emissions of DFGD waste will be controlled using a new multi-compartment pulse jet fabric filter (PJFF), commonly called a baghouse. Waste collected in the PJFF hoppers will be pneumatically transported to the recycle ash storage silo for use as a reagent in the DFGD system. Excess waste will be pneumatically transported to a DFGD waste ash silo for disposal off-site. ESP fly ash will be blended into the DFGD waste to stabilize it. The blending ratio will be a maximum of 10% ESP fly ash.

For the following reasons a new baghouse is proposed instead of trying to use the existing ESP for particulate control:

- SO_2 Emissions Control
  Utilizing a baghouse downstream of a dry FGD will provide a higher sulfur removal rate than utilizing an ESP. A DFGD/ESP combination would be expected to remove only about 70% of the sulfur while a DFGD/baghouse combination is capable of removal rates in the 90% range. In addition, using a baghouse will also lower emissions of HCl and HF compared to an ESP. Grand River Dam Authority Unit 2 is an example of a plant that utilizes an ESP with a Dry FGD and has an approximate sulfur removal rate of 70%.
- Particulate Emissions
  If a dry FGD were added upstream of an existing ESP, the amount of dust loading in the ESP would be increased and the character of the dust loading would change. This would raise concerns of whether the plant could continue to meet particulate emissions limits without major ESP modifications.
- Outage Duration
  A new baghouse with interconnecting ductwork could be completely installed prior to a tie-in outage whereas any ESP and ESP inlet and outlet duct modifications would have to take place during an outage. This would increase the required tie-in outage duration and increase power replacement costs for the project.

5. BOOSTER FANS

Two 50% capacity axial booster fans will be provided on each unit.

6. CHIMNEY

The existing chimneys will be reused. The height of the chimney is 500 feet above grade. The top 50’ on the interior of each steel chimney and exterior of the concrete shell will have an acid resistant coating applied to mitigate the effects of acid condensation.

7. MATERIAL HANDLING SYSTEM

7.1 FLY ASH HANDLING SYSTEM

DFGD waste collected in the PJFF hoppers will be pneumatically transported to the recycle storage silo for use as a reagent in the DFGD system. Excess waste will be pneumatically transported to the DFGD waste silos for disposal off site.

Filter separators will be provided on the recycle ash storage silo and the DFGD waste ash silo for control of fugitive fly ash emissions.

7.2 LIME HANDLING SYSTEM

Lime will be delivered to each site via truck. The lime would be pneumatically transferred to a 14-day lime storage silo. From the 14-day storage silo, lime would be pneumatically conveyed to a 24-hour lime day bin located at the DFGD system reactant preparation building for each unit. One day bin will be located at each unit.

Fugitive emissions will be controlled using bin vent filters located on the 14-day lime storage silo and the 24-hour lime day bins.

8. COST ESTIMATING BASIS

Two separate cost estimates will be developed for this study. One estimate will be developed for Sooner Units 1 and 2, and the other for Muskogee Units 4 and 5.

8.1 SOONER ESTIMATE SCOPE

The Sooner Station cost estimate will be based on the following scope:

- Unit 1 Spray Dryer Absorber Area
- Unit 2 Spray Dryer Absorber Area
- Units 1 and 2 Common Areas (lime unloading and waste handling)
- Auxiliary Power System
- Booster ID Fans
- Baghouses

8.2 MUSKOGEE ESTIMATE SCOPE

The Muskogee Station cost estimate will be based on the following scope:

- Unit 4 Spray Dryer Absorber Area
- Unit 5 Spray Dryer Absorber Area
- Units 4 and 5 Common Areas (lime unloading and waste handling)
- Auxiliary Power System

- Booster ID Fans
- Baghouses

8.3 COMMERCIAL BASIS

8.3.1 Equipment and Material Cost

Equipment and material costs will be based on vendor budgetary quotes, estimated quantities, and the S&L in-house database.

8.3.2 Labor Wage Rates

Labor wage rates will be based on an open shop Oklahoma labor force.

8.3.3 Labor Crews

The construction and erection labor cost is based on the use of applicable construction crews typically required for projects of this type.

8.3.4 Productivity

No allowances have been made to cover items such as the loss in productivity because of inability to attract labor, weather conditions, etc.

8.3.5 Quantity Sources

All quantity data was developed internally by S&L Lead Engineers.

8.3.6 Project Schedule

The project schedule is attached.

8.3.7 Indirect Expenses

The engineering costs included herein are estimated and are not to be interpreted as a proposal by S&L to perform engineering services. The indirect expenses also include Owner's Construction Management, General Owner's Costs, and Owner's Bond Fees.

8.3.8 Escalation Rates

a. Equipment escalation is assumed to be 2.5% for 2010 and 4.0% for 2011 through 2014. Based on project schedule, it is assumed that for Sooner 30% of the equipment will be purchased in 2012 with the balance purchased in 2013. No major equipment procurement is anticipated past 2013.

b. Material escalation is 0.0% for 2010, 3.0% for 2011, and 5.0% for 2012 and beyond. Based on project schedule, it is assumed for Sooner that 10% of the material will be purchased in 2012, 50% in 2013, and 40% in 2014.

c. Labor escalation is 3.0% for 2010 and 4.0% for 2011-2014. Based on project schedule, it is assumed that for Sooner 10% of the labor cost will be spent in 2012, 50% in 2013, and 40% in 2014.

d. Escalation for indirects is 3.0% for 2010 and 4.0% for 2011-2015. Based on project schedule, it is assumed that for Sooner 20% of indirects will be spent in 2011, 40% in 2012, 30% in 2014, and 10% in 2015.

8.3.9 Sales/Use Taxes

It has been assumed the project will be structured to avoid sales tax. Therefore, Sales/Use Taxes are estimated at 0% of equipment and material.

8.3.10 Contingency

Contingency is estimated at 14.04% of total direct and indirect costs based on a 95% confidence level.

8.3.11 AFUDC Rate

AFUDC is calculated as 8.66% from 2010 based on information received from OG&E.

8.3.12 Bond Fees

Bond fees are estimated at 1% based on typical bond fees and the level of project equity.

8.3.13 General Owner's Cost

General Owner's Cost is estimated at 5% of Total Direct Cost.

8.4 TECHNICAL BASIS

The following is a summary of the technical basis of the spray dryer absorber FGD system capital cost estimate.

8.4.1 Common Lime Handling Systems

A common lime handling system will be installed at each station. The lime handling systems will be capable of unloading and conveying lime to day bins at each unit.

a. Lime truck unloader

i. Lime will be brought on site in trucks.

ii. The system will be vacuum pneumatic to unload the truck.

iii. The blowers will be housed in the skirt of the lime storage silo.

iv. A ventilation system and dust collector will provide dust control.

b. Lime storage silo

i. One common lime storage silo will be provided to house 14-days of lime usage while burning the design coal.

ii. The storage silo will be made of concrete.

iii. The total storage will be 3000 tons.

iv. The Lime silo will be 36-feet in diameter and 95-feet tall.

v. Bin vent filters will be provided on the concrete silo for dust control.

vi. The silo will have a two-hopper outlet.

c. Lime transfer systems

i. Two runs of pneumatic, pressurized pipe from the lime silo to the lime prep day bins

ii. Piping will be located on an above grade pipe rack

8.4.2 Lime Preparation and Recycle Area per Unit

Each unit will have the following equipment in the quantities listed below. Both the lime preparation and recycle area for each unit will be located in the same building. Therefore, each unit will have a lime preparation and recycle of the dimensions 55 ft x 100 ft x 125 ft in height.

a. Lime preparation

i. Two 100% ball mill lime slakers each with a grit screen and gravimetric feeder.

ii. Two lime transfer tanks.

iii. Two lime slurry storage tanks.

iv. Two slurry feed centrifugal pumps.

v. Two slurry transfer centrifugal pumps

vi. One lime day bin

vii. The equipment, tanks, and day bin will be enclosed by a preparation building of the dimension: 100 ft x 55 ft x 125 ft

b. Each unit will be equipped with a recycle area to recycle lime byproduct through the absorber process.

i. One (1) recycle storage silo

ii. Two (2) recycle mix tanks

iii. Two (2) recycle slurry tanks each with two (2) recycle slurry centrifugal pumps per tank

iv. Agitators for each tank

8.4.3 Absorber Area per Unit

Each unit will be equipped with the absorber equipment detailed below.

a. Two (2) absorber vessels per unit, with access doors

b. Rotary atomizers or dual fluid nozzles, spare atomizers will be included

c. The vessel material will be carbon steel of a thickness between 1/4 in. and 5/8 in.

d. A penthouse enclosure for the absorbers.

e. Each absorber will be provided with 6-inches of insulation and lagging.

f. Heating and ventilation equipment will be provided for each absorber structure.

g. Vacuum piping

h. Vendor quotes have confirmed that two SDA's will be utilized per unit.

8.4.4 Baghouse FGD Waste Handling System Common to Both Units

A baghouse will be installed on each unit after the SDA's to capture FGD waste. The baghouses will be sized to handle the FGD waste produced by each unit. Each station will have an FGD waste handling system to convey FGD waste from the baghouses to storage locations. The waste handling systems will be sized to handle the FGD waste produced by each unit.

a. New pipe and blowers will be required to convey waste from the new baghouses. A new ash handling blower building of the dimensions 25 ft x 50 ft x 25 ft high will be provided, per unit.

b. Addition of one new 3-day storage DFGD waste silo for truck unloading.

   i. The DFGD waste silo will be concrete, 30' in diameter by 68' tall.

   ii. The silo capacity will be 1,500-tons.

c. A new ESP fly ash silo will be added near the DFGD waste silo for fly ash blending to stabilize the FGD waste.

   i. The fly ash silo will be concrete, 20' in diameter by 46' tall.

   ii. The fly ash silo capacity will be 450-tons.

   iii. A pin mixer for fly ash conditioning

8.4.5 Flues Including Support Steel per Unit

Each unit will require additional ductwork to bring the flue gas from the existing ID fans to the absorbers, absorbers to the baghouses, baghouses to the new booster fans, and new booster fans to the existing chimney.

a. ID Fan Outlet to Absorber Inlet

   i. Carbon steel ¼ in.

   ii. Velocity 4000 fpm

   iii. 6" insulation with lagging

b. Absorber Outlet to Baghouse Inlet

   i. Carbon steel, ¼ in.

   ii. Velocity 4000 fpm

   iii. 6" insulation with lagging

c. Baghouse Outlet to Axial Booster Fan

i. Carbon steel, ¼ in.

ii. Velocity 4000 fpm

iii. 4" insulation with lagging

d. Booster Fan Outlet to Chimney

i. Carbon steel, ¼ in.

ii. Velocity 4000 fpm

iii. 4" insulation with lagging

8.4.6 Control System Modifications

The control system modification estimates are based on the estimated number of I/O points added to each unit and to the common system for each Station. In total, the entire dry FGD system will require approximately 4,500 new I/O points at each Station, broken down as follow**.**

a. Each individual unit will require approximately 1,250 I/O points. This includes the SDA's and reagent prep areas.

b. The common area at each station will require approximately 2,000 I/O points.

8.4.7 Subsurface and Foundation Work, Both Stations

Based on the Sooner soil reports, deep foundations (piles and caissons) are not required and are not included in the cost estimate.

The existing storm drainage system in the DFGD area will have to be removed and replaced to make room for the new foundations associated with the DFGD system.

8.4.8 Civil Work, Both Stations

The civil work required will be typical to both stations. New roads will be paved for lime trucks and maintenance access. All other areas will be finished with white rock surfacing.

8.4.9 Construction Work, Both Stations

Construction labor will be drawn from the same workforce for work on both stations. The workforce is detailed below.

a. Labor will be open shop labor based out of Oklahoma.

b. The workforce wages will include premiums and per diems.

c. Labor is based on a 5x10 work week

d. No incentives to attract labor are included

8.4.10 Pipe Racks

Pipe racks will be installed common to both units at each station as detailed below.

a. A pipe rack for lime transport piping will be installed between the lime unloading area and the lime storage silos.

b. A pipe rack for lime slurry piping from the lime slakers to the SDA's

c. A pipe rack for lime transport piping will be installed between the lime silo and reagent prep area.

d. A pipe rack for FGD waste transport will be installed between the baghouse and new fly ash silos.

e. A pipe rack for recycle transfer from the baghouses to the recycle prep area.

f. A pipe rack for recycle slurry to the SDA's

g. One pipe rack per unit for cabling from the Auxiliary Transformers to the reagent areas.

8.4.11 Chimney Modifications

Each unit will re-use its existing chimney. The interior top 50 feet of each steel chimney liner will have an acid resistant coating applied to mitigate the effects of acid condensation.

8.4.12 Baghouse Sizing

A new baghouse will be installed at each unit. The baghouses will be used to remove DFGD waste from the flue gas stream. Estimates will be based on vendor input from Siemens and B&W.

8.4.13 Demolition and Relocation

a. Sooner Station

i. The existing storm drainage system in the DFGD area will be removed and replaced.

ii. Ash piping in the vicinity of the existing ID fans will be relocated and re-supported to make room for the new ductwork.

b. Muskogee Station

i. A prefabricated maintenance and material storage warehouse will require relocation at Muskogee Station.

8.4.14 CEMS

Each Unit's existing CEMS will be reused. No modifications are required.

8.4.15 Water Treatment at Each Station

Water containing a sulfate content of less than 200 mg/L is considered good, and less than 500 mg/L is considered acceptable. Sooner Station will obtain its water from the Sooner Reservoir, which has a sulfate content below 200 mg/L and Muskogee Station will draw its water from the Arkansas River which also has a sulfate content below 200 mg/L. Therefore, water treatment, aside from strainers, will not be required at either station.

8.4.16 Instrument Air Compressors and Dryers, per Station

Each Station will require new instrument air compressors and dryers to expand the existing instrument air systems. The required sizing is discussed below.

a. 2 x 100% air compressors sized for 250 scfm each at 100 psig.

b. 2 x 100% instrument air dryers with filters, sized for 250 net scfm each.

8.4.17 Field Painting, All Units

All exposed ductwork will be painted with a multiple coat paint system. All other exposed steel with painted with an inorganic zinc primer and polyurethane system.

8.4.18 Performance Testing

Performance testing is included as part of the Owner's costs in the estimate tabulation.

8.4.19 Construction Support

Construction support will be required at each station. It is estimated that support will be required for 12 months, at an average of 1.5 persons per station.

8.4.20 Piping per Unit

Each Unit will require new instrument air piping run as a header from the new instrument air dryers. Instrument air takeoffs will be run from the headers to each lime silo or day bin, bin vent, and reagent preparation and recycle area.

8.4.21 New Booster Fans

New axial booster fans will be required to overcome the additional pressure drop seen through the SDA's and baghouses.

a. Two 3500 hp axial ID fans will be installed on each unit. These fans will be arranged in a 2 x 50% configuration.

b. The price includes foundations and motors. A spare motor is not included.

c. Vendor quotes from TLT Babcock, Howden, and Flakt Woods have been received.

8.4.22 Electrical per Station

The electrical items discussed below summarize everything required to power the new DFGD area at each Station

a. One additional startup transformer will be required at each station. i.e. one at Sooner and one at Muskogee.

b. One unit auxiliary transformer will be required per unit, totaling two per station. Each UAT will be housed in a pre-engineered building.

c. Medium voltage switchgear for each unit.

d. One 480 V switchgear for reagent preparation, recycle, and SDA at each unit.

e. One pre-engineered reagent preparation electrical equipment building for each unit.

Attachment 1

Mass Balance Diagrams for

Sooner Station and Muskogee Station

This page inserted by Oklahoma Department of Environmental Quality.

Comments

of

Oklahoma Gas and Electric Company

on

Regional Haze Implementation Plan Revision

Attachment 1 of Exhibit 3 of the comments submitted by OG&E on December 16, 2009 includes 4 pages that have been identified as confidential information. These pages include mass balance diagrams for Sooner Station and Muskogee Station and have been removed as provided by 27A O.S. § 2-5-105(17).

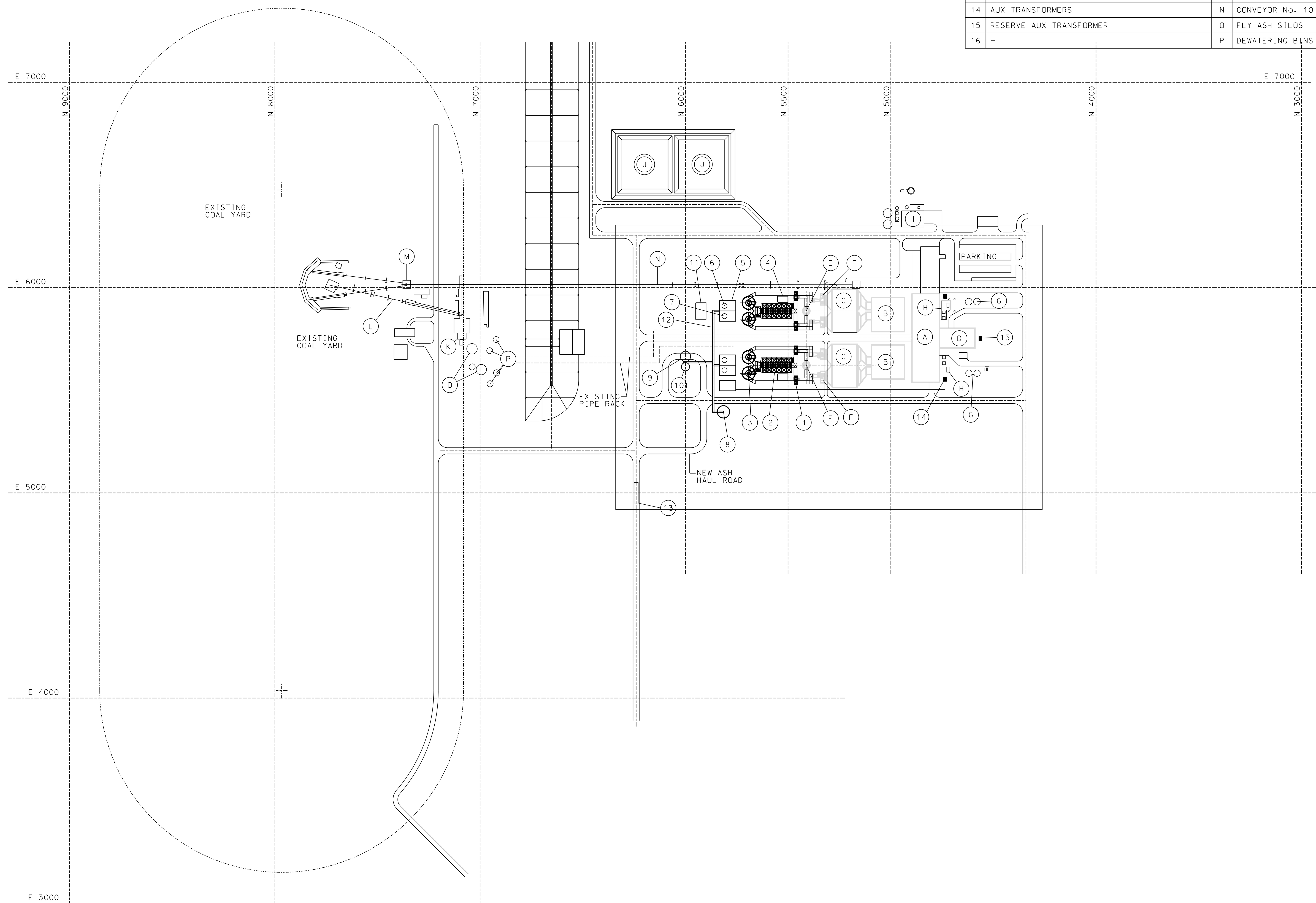
Attachment 2

Sooner Station

General Arrangement Drawing

LEGEND	
NEW EQUIPMENT	
01	BOOSTER FANS
02	FABRIC FILTER
03	SPRAY DRYER ABSORBER
04	ASH BLOWER BUILDINGS
05	RECYCLE/LIME PREP. BUILDING
06	RECYCLE SILOS
07	LIME DAY BINS
08	LIME STORAGE SILO
09	WASTE ASH SILO
10	FLY ASH SILO
11	ELECTRICAL EQUIPMENT ROOM
12	PIPE RACK
13	INBOUND/OUTBOUND BELT SCALE
14	AUX TRANSFORMERS
15	RESERVE AUX TRANSFORMER
16	-

LEGEND	
EXISTING EQUIPMENT	
A	TURBINE BUILDING
B	BOILER BUILDING
C	PRECIPITATOR
D	CONTROL ROOM
E	STACK
F	ID FANS
G	CONDENSATE STORAGE TANKS
H	MAIN TRANSFORMER
I	WATER TREATMENT BUIDLING
J	LIGHT OIL STRAGE TANKS
K	CAR DUMPER
L	CONVEYOR No.2
M	CRUSHER HOUSE
N	CONVEYOR No. 10 & 11
O	FLY ASH SILOS
P	DEWATERING BINS



200 0 200 400 600
GRAPHIC SCALE
DRAWING SCALE

HOLD INFORMATION		
NO.	DATE	DESCRIPTION
△		

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION		
REV.	DATE	DESCRIPTION
A	11/20/2009	FOR CLIENT COMMENTS

ISSUE PURPOSE:
SPECIFICATION:
PROJECT NO.: 11418-019

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ENTER NAME.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: SK-GA-SNR-01.DGN
PREPARED BY: R. MILLER
REVIEWED BY: D. RICE
APPROVED BY:

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC

SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780
WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

OG+E

PROJECT

SOONER GENERATING STATION

UNITS 1 & 2
OKLAHOMA GAS & ELECTRIC
RED ROCK, OKLAHOMA

DRAWING TITLE

PRELIMINARY
GENERAL ARRANGEMENT

DRAWING NUMBER	REVISION
SK-GA-SNR-01	A

SHEET 1 OF 1

ZL5825/0n0920/D:*SOONER STATION*NEW OPTION - 2009*SK-GA-SNR-01_A.dgn
Form GDG-0401-01-08. ANSI (Imperial) MicroStation Border - Size E - 34 x 44
Revision 9. Revision Date: 12-19-2008

12/7/2009 2:15:30 PM
...*SK-GA-SNR-01_A.dgn

Attachment 3

Sooner Station

Power Requirement Tables

Summary of DFGD/BAGHOUSE Power Consumption
Sooner Unit 1 or 2

Inputs:	Capacity	Heat Input	SDA Inlet Flow*	SDA Outlet Flow*	Booster Fan Inlet Flow*	Max. Sulfur in Coal	HHV	Inlet SO_2	Max. Lime*
	MWg	mmBtu/hr	acfm	acfm	acfm	%	Btu/lb	lb/mmBtu	lb/hr
Sooner Unit 1 or 2	570	5,116	1,910,947	1,724,051	1,764,944	0.48	8,084	1.176	8,908

*From S&L mass balance

	Connected	Operating	Load per Motor HP	Load per Motor kW	CONNECTED HP	CONNECTED kW	OPERATING HP	OPERATING kW	Operating Usage
Absorber Island									
Atomizers	2	2	960	716	1920	1432	1920	1432	
Penthouse Heaters	2	2		50		100		100	(winter)
Dampers	2	2	5	4	10	7	10	0.1	2% time
Miscellaneous	0.5 to 10 HP motors		30	22	30	22	3	2	10% time
Total						**1562**		**1535**	

	Connected	Operating	Load per Motor HP	Load per Motor kW	CONNECTED HP	CONNECTED kW	OPERATING HP	OPERATING kW	Operating Usage
Reagent Preparation and Recycle Island									
Lime Unloading Blower	2	1	300	224	600	448	30	22	10% time
Silo Live Bottom	2	1	7	5	14	10	7	5	
Lime Feeder	2	1	5	4	10	7	5	4	
Ball Mill Slaker	2	1	110	82	220	164	110	82	
Slurry Tank Agitator	2	1	40	30	80	60	40	30	
Slurry Feed Pump	2	1	20	15	40	30	20	15	
Recycle Silo Fluidization Air Blower	2	1	20	15	40	30	20	15	
Recycle Silo Fluidization Air Heater	2	1		40		80		40	
Recycle Slurry Mixer	2	1	150	112	300	224	150	112	
Recycle Feed Pump	2	1	40	30	80	60	40	30	
Miscellaneous	0.5 to 10 HP motors		20	15	20	15	10	7	50% time
Total						**1127**		**362**	

Summary of DFGD/BAGHOUSE Power Consumption
Sooner Unit 1 or 2

	Connected	Operating	Load per Motor HP	Load per Motor kW	CONNECTED HP	CONNECTED kW	OPERATING HP	OPERATING kW	Operating Usage
Baghouse/Ash Handling Island									
Compressor	2	1	500	373	1000	746	250	187	50% time
Hopper Heater	16	16		260		260		130	50% time
Penthouse Heaters / Hopper Enclosure Heaters	12	12		240		240		120	50% time
Transport Air Vac. Blowers	2	1	150	112	300	224	150	112	
Miscellaneous	0.5 to 10 HP motors		50	37	50	37	10	7	20% time
Total						**1507**		**556**	

	Connected	Operating	Load per Motor HP	Load per Motor kW	CONNECTED HP	CONNECTED kW	OPERATING HP	OPERATING kW	Operating Usage
Booster Fan System w FGD									
Booster Fan with FGD	2	2	3280	2450	6560	4890	6560	4890	
Miscellaneous	0.5 to 10 HP motors		20	10	20	15	20	15	
Total						**4900**		**4900**	

Total Aux. Power		Connected (MW)	Operating (MW)	
FGD System only (SDA+BH)	Base	4.2	2.5	
	Total	**4.2**	**2.5**	
SDA/Baghouse/Booster Fans	Base	9.1	7.4	
	Total	**9.1**	**7.4**	**1.29%**

Summary of DFGD/BAGHOUSE Power Consumption
Muskogee Unit 4 or 5

Inputs:	Capacity	Heat Input	SDA Inlet Flow*	SDA Outlet Flow*	Booster Fan Inlet Flow*	Max. Sulfur in Coal	HHV	Inlet SO_2	Max. Lime*
	MWg	mmBtu/hr	acfm	acfm	acfm	%	Btu/lb	lb/mmBtu	lb/hr
Muskogee Unit 4 or 5	572	5,480	2,046,910	1,846,716	1,890,519	0.48	8,084	1.176	9,541

*From S&L mass balance

	Connected	Operating	Load per Motor HP	Load per Motor kW	CONNECTED HP	CONNECTED kW	OPERATING HP	OPERATING kW	Operating Usage
Absorber Island									
Atomizers	2	2	1020	761	2040	1522	2040	1522	
Penthouse Heaters	2	2		50		100		100	(winter)
Dampers	2	2	5	4	10	7	10	0.1	2% time
Miscellaneous	0.5 to 10 HP motors		30	22	30	22	3	2	10% time
Total						**1652**		**1624**	

	Connected	Operating	Load per Motor HP	Load per Motor kW	CONNECTED HP	CONNECTED kW	OPERATING HP	OPERATING kW	Operating Usage
Reagent Preparation and Recycle Island									
Lime Unloading Blowe	2	1	320	239	640	477	32	24	10% time
Silo Live Bottom	2	1	8	6	16	12	8	6	
Lime Feeder	2	1	5	4	10	7	5	4	
Ball Mill Slaker	2	1	120	90	240	179	120	90	
Slurry Tank Agitator	2	1	40	30	80	60	40	30	
Slurry Feed Pump	2	1	30	22	60	45	30	22	
Recycle Silo Fluidization Air Blowe	2	1	30	22	60	45	30	22	
Recycle Silo Fluidization Air Heate	2	1		40		80		40	
Recycle Slurry Mixer	2	1	150	112	300	224	150	112	
Recycle Feed Pump	2	1	40	30	80	60	40	30	
Miscellaneous	0.5 to 10 HP motors		20	15	20	15	10	7	50% time
Total						**1203**		**387**	

Summary of DFGD/BAGHOUSE Power Consumption
Muskogee Unit 4 or 5

	Connected	Operating	Load per Motor HP	Load per Motor kW	CONNECTED HP	CONNECTED kW	OPERATING HP	OPERATING kW	Operating Usage
Baghouse/Ash Handling Island									
Compressor	2	1	540	403	1080	806	270	201	50% time
Hopper Heater	16	16		260		260		130	50% time
Penthouse Heaters / Hopper Enclosure Heaters	12	12		240		240		120	50% time
Transport Air Vac. Blowers	2	1	150	112	300	224	150	112	
Miscellaneous	0.5 to 10 HP motors		50	37	50	37	10	7	20% time
Total						**1567**		**571**	

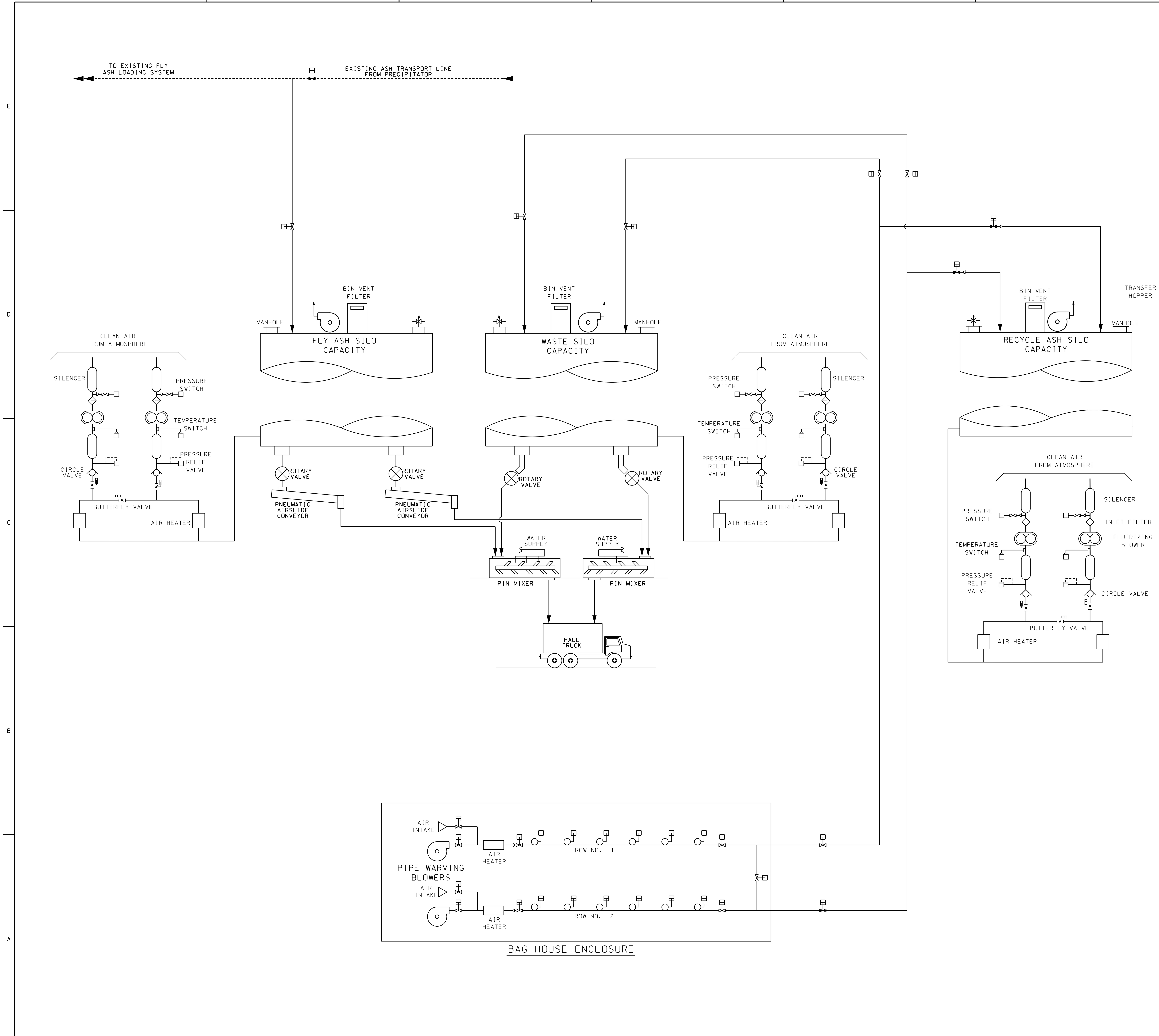
	Connected	Operating	Load per Motor HP	Load per Motor kW	CONNECTED HP	CONNECTED kW	OPERATING HP	OPERATING kW	Operating Usage
Booster Fan System w FGD									
Booster Fan with FGD	2	2	3520	2630	7040	5250	7040	5250	
Miscellaneous	0.5 to 10 HP motors		20	10	20	15	20	15	
Total						**5260**		**5260**	

Total Aux. Power		Connected (MW)	Operating (MW)	
FGD System only (SDA+BH)	Base	4.4	2.6	
	Total	**4.4**	**2.6**	
SDA/Baghouse/Booster Fans	Base	9.7	7.8	
	Total	**9.7**	**7.8**	**1.37%**

Attachment 4

Sooner Station Units 1 and 2

Material Handling Diagrams



HOLD INFORMATION

NO.	DATE	DESCRIPTION
△		

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION
A	2009	FOR COMMENTS

ISSUE PURPOSE:

SPECIFICATION:

PROJECT NO.: 11418-019

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ENTER NAME.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

ENGINEER SEAL

CAD FILE NAME: SNR-MHS-2.DGN

PREPARED BY: D.AMIN

REVIEWED BY: S.MADAN

APPROVED BY:

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC
SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780
WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

CLIENT LOGO

PROJECT

SOONER GENERATING STATION

UNITS 1 & 2
OKLAHOMA GAS & ELECTRIC
RED ROCK, OKLAHOMA

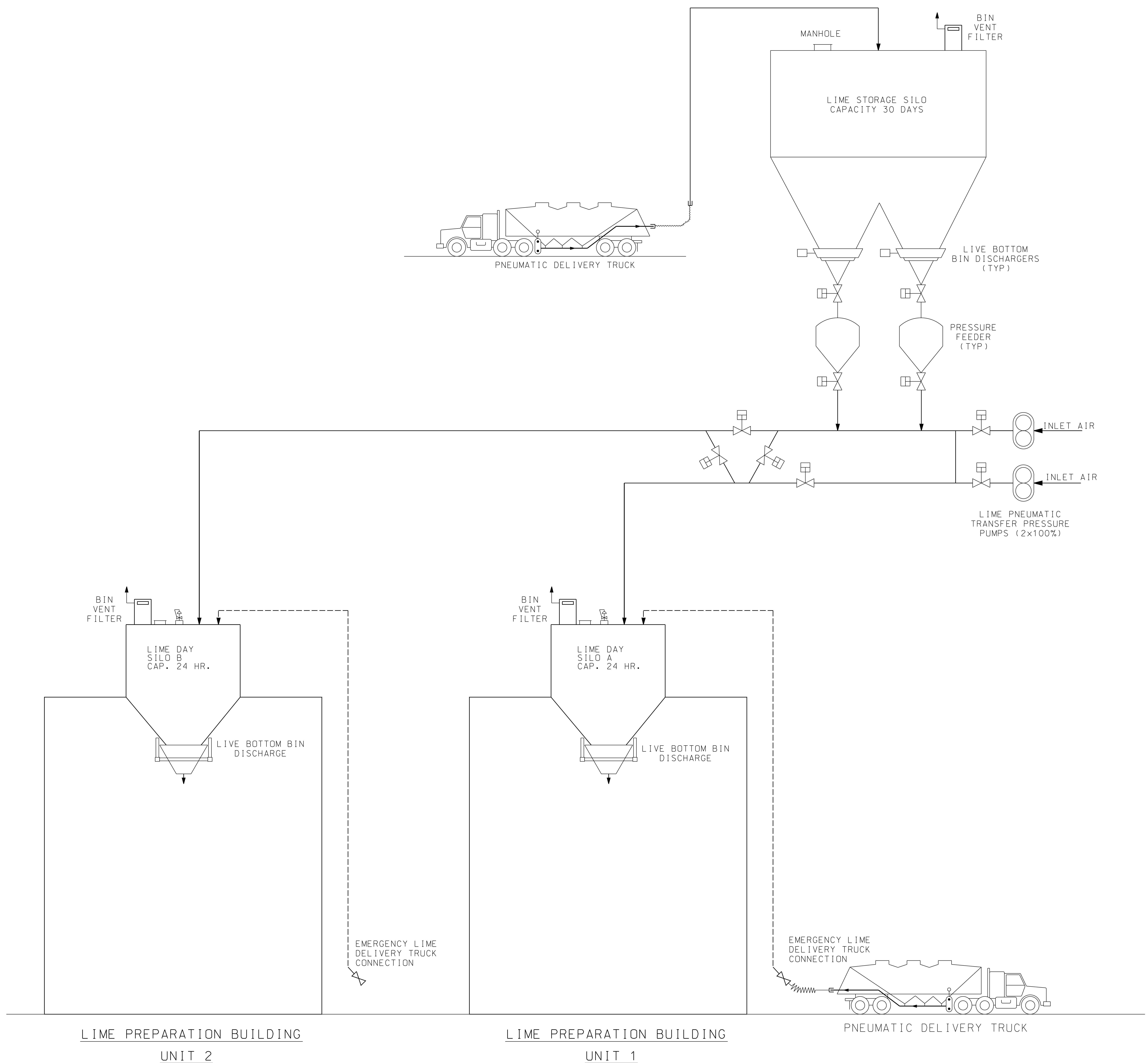
DRAWING TITLE

FLOW DIAGRAM FOR FLY ASH / WASTE HANDLING SYSTEM

DRAWING NUMBER	REVISION
SNR-MHS-02	A

SHEET 1 OF 1

ZL5825/On0920/D:#SOONER STATION#NEW OPTION - 2009#SNR-MHS-3.dgn
Form GDG-0401-01-08, ANSI (Imperial) MicroStation Border - Size E - 34 x 44
Revision 9, Revision Date: 12-19-2008
12/7/2009 8:48:29 AM
...#SNR-MHS-3.dgn



HOLD INFORMATION

NO.	DATE	DESCRIPTION

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION
A	11/20/2009	FOR CLIENT COMMENTS

ISSUE PURPOSE:

SPECIFICATION:

PROJECT NO.: 11418-019

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ENTER NAME.

ENTER NAME
ENTER DATE

ENGINEER SEAL

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: RED-MHS-1.DGN

PREPARED BY: D.AMIN

REVIEWED BY: S.MADAN

APPROVED BY:

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC

SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780
WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

OG/E CLIENT LOGO

PROJECT

SOONER GENERATING STATION

UNITS 1 & 2
OKLAHOMA GAS & ELECTRIC
RED ROCK, OKLAHOMA

DRAWING TITLE

FLOW DIAGRAM FOR
LIME HANDLING SYSTEM

DRAWING NUMBER	REVISION
SNR-MHS-01	A

SHEET 1 OF 1

Attachment 5

Summary of Vendor Quotations

DFGD Budgetary Proposal Pricing

Date: 12/11/2009

PROPOSAL PRICING COMPARISON FOR OG&E - SOONER UNITS 1&2 DFGD SYSTEM				
Equipment Description	**Bidder 1**	**Bidder 2**	**Bidder 3**	**Average Cost**
Lime preparation	$5,010,000	$20,000,000	Incl with Other Misc	
Absorber Equipment	$20,962,000	$16,000,000	$21,400,000	
Recycle System	$4,506,000	$4,000,000	Incl with Other Misc	
Fabric Filter	$13,054,000	$26,000,000	$23,600,000	
Compressor System	$2,670,000	$2,000,000	Incl with Other Misc	
Other Misc Equipment	$10,820,000	$4,000,000	$33,000,000	
Total Equipment (Units 1&2)	**$57,022,000**	**$72,000,000**	**$78,000,000**	**$69,007,333**
S&L Cost Estimate for Sooner 1&2		**$70,500,000**		
Erection Budget Price (Units 1&2)	**$62,384,000**	**$67,270,000**	**$73,036,000**	**$67,563,333**
S&L Cost Estimate for Sooner 1&2		**$65,753,000**		
Note: Bidders 2 and 3 provided estimated erection manhours. Budget erection cost is calculated based on current S&L Cost Estimate using $62/mhr for mechanical labor cost (non-union) and 55% markup for Crane+scaffolding+mob/demob+Overtime+ Per diem+G&A+Profit				
Note: S&L Cost estimate was performed based on our historical pricing information for Equipment/Material and Labor Costs. Labor costs were developed independently from the three bidders				

Attachment 6

Project Schedule

Activity ID	Activity Description	Orig Dur	Start	Finish
DFGD				
PRELIMINARY ENGINEERING				
SLN1001	Project Authorization	0	01FEB11*	
SLN1G01020	Develop FGDs GAs and Engineering Studies	140	01FEB11	16AUG11
SLN1G01090	Prepare Design Criteria	84	05APR11	01AUG11
SLN1G01608	Prepare Preliminary Site Arrangement Dwgs	23	31MAY11	30JUN11
EPC SPEC				
SLN1110	DFGD Sys EPC Spec - Bid Issue to Client	40	01FEB11	28MAR11
SLN1118	DFGD Sys EPC Spec- Bid Issue to Vendors	5	29MAR11	04APR11
SLN1120	Vendor Bid Period	60	05APR11	27JUN11
SLN1130	Evaluate Bids	30	28JUN11	09AUG11
SLN1140	Negotiation	40	10AUG11	04OCT11
SLN1150	Award EPC	0		04OCT11
PERMITTING				
SLP0000108	FGD Other Permits	978	02AUG11*	15MAY15
SLN2P00001	Air Permit: Dry FGD Prepare/Submit	636	30AUG11	14FEB14
ENGINEERING - ALL UNITS				
SLNSUM1900	Ductwork Design	472	15JUN12	15APR14
SLNSUM0500	BOP Piping & Hanger Design	586	25JUN12	01OCT14
SLNSUM0510	Electrical Design	654	28JUN12	12JAN15
SLNSUM0520	Substructure Design	461	09JUL12	21APR14
SLNSUM0800	Steel Design	450	09JUL12	04APR14
SLNSUM1060	Develop Preliminary P&ID's	206	18JUL12	03MAY13
SLNSUM0550	P&I ID Preparation	482	19SEP12	01AUG14
SLNSUM0600	Electrical Wiring	533	22JAN13	13FEB15
MAJOR PROCUREMENT - ALL UNITS				
SLN1M10000	DFGD Spec - Bid Issue	60	19OCT11	12JAN12
SLN1M10060	DFGD Spec - Award Contract	0		11APR12
SLN1M23600	Fabric Filter Bid/Award	100	12APR12	30AUG12
SLN1M13500	ID Booster Fans - Bid/Award	92	07MAY12	12SEP12
SLN1E17500	Switchyard/TL Upgrades Bid/Award	92	29MAY12	04OCT12

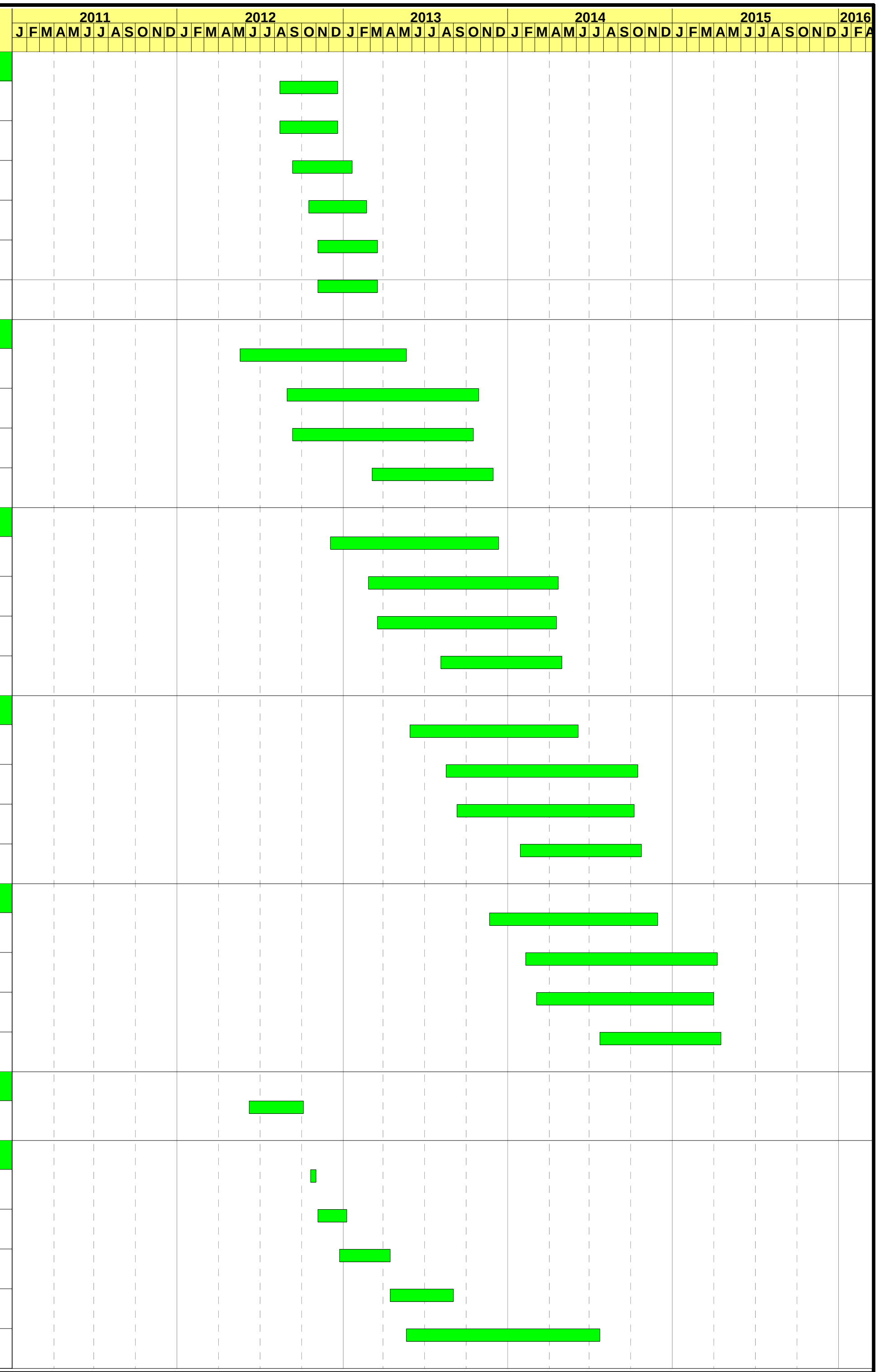
Start Date 31MAY10
Finish Date 26FEB16
Data Date 01JUN10
Run Date 30NOV09 13:26

DF01

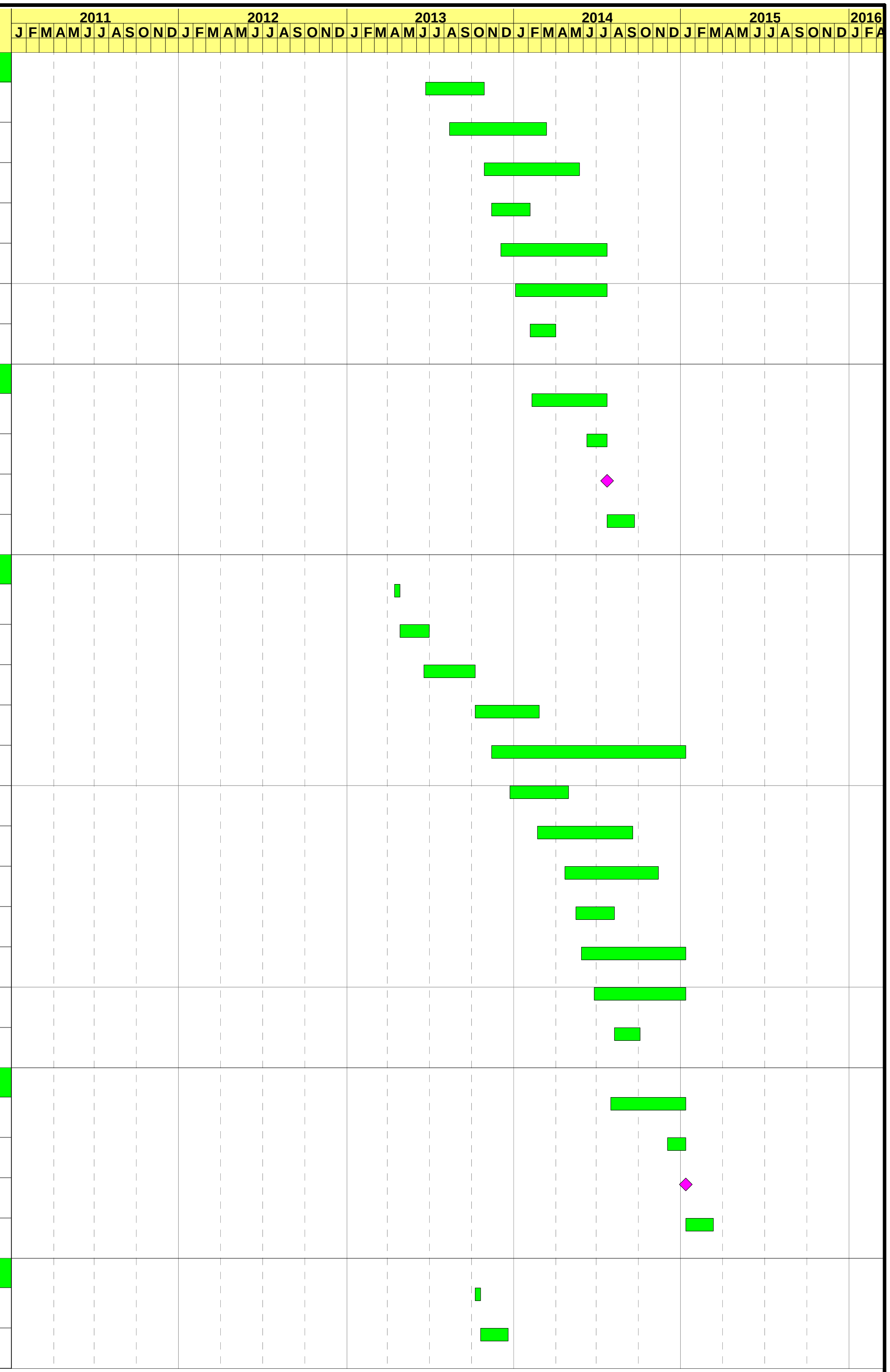
OKLAHOMA GAS & ELECTRIC
Sooner & Muskogee Stations DFGD Prj
SUMMARY SCHEDULE

Sargent & Lundy LLC

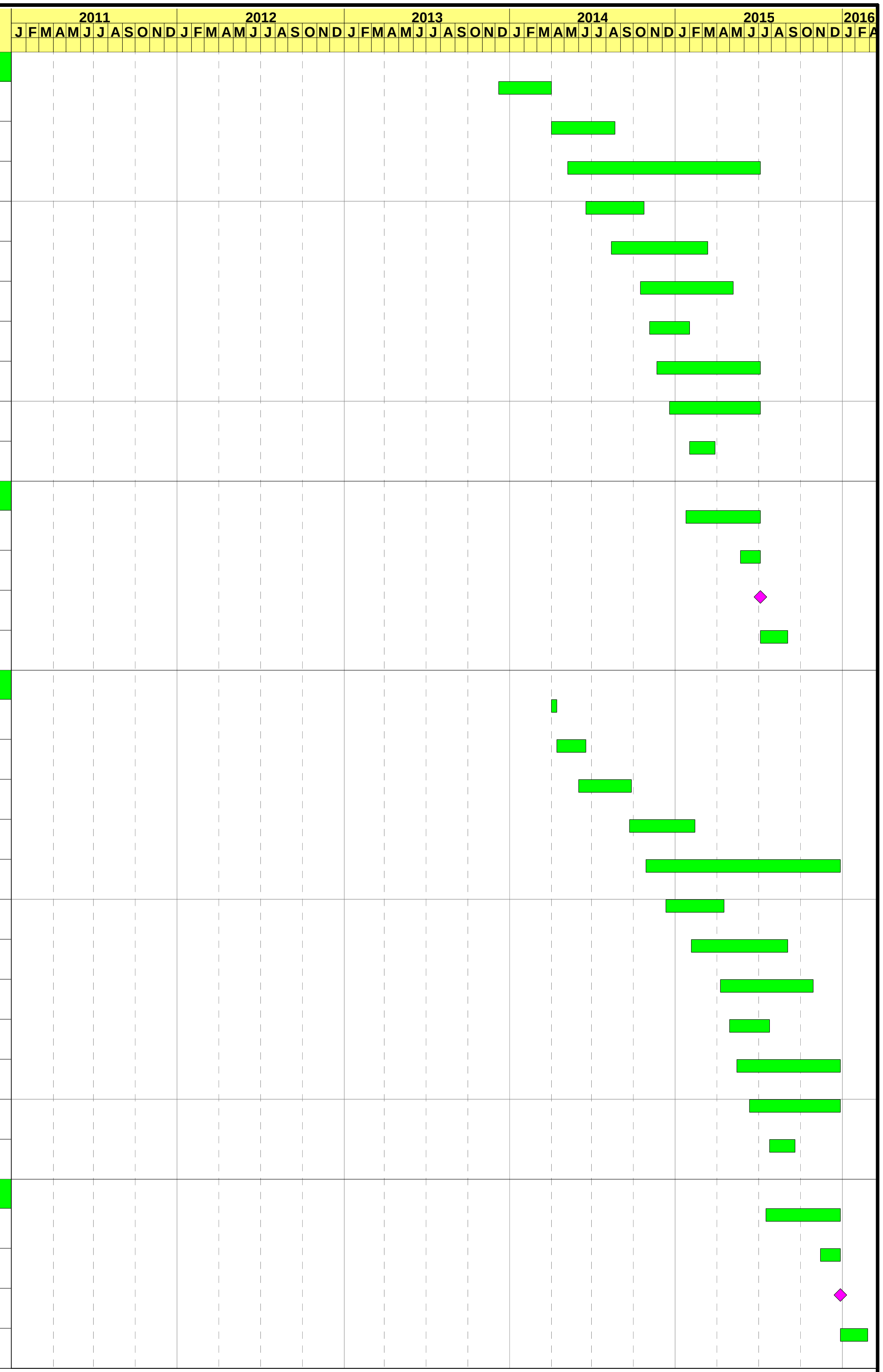
Activity ID	Activity Description	Orig Dur	Start	Finish
MAJOR PROCUREMENT - ALL UNITS				
SLN2S12000	Ductwork Bid/Award	92	13AUG12	18DEC12
SLN2S13000	Structural Steel Bid/Award	92	13AUG12	18DEC12
SLN1ES7000	Aux Transformer Bid/Award	92	13SEP12	22JAN13
SLN2E18000	Medium Voltage Switchgear Spec - Prep/Rvw/Award	92	16OCT12	22FEB13
SLN2F15000	DCS Bid/Award	92	08NOV12	19MAR13
SLN2M16000	Dampers Bid/Award	92	08NOV12	19MAR13
FABRICATION / DELIVERY - SOONER U1				
FDS10010	DFGD Fabrication & Delivery - Sooner U1	262	17MAY12	22MAY13
FDS10020	Fabric Filter Fabrication & Delivery - Sooner U1	300	31AUG12	29OCT13
FDS10030	ID Booster Fan Fab & Delivery - Sooner U1	280	13SEP12	14OCT13
FDS10040	Aux Transformer Fab & Delivery - Sooner U1	190	06MAR13	27NOV13
FABRICATION / DELIVERY - SOONER U2				
FDS20010	DFGD Fabrication & Delivery - Sooner U2	262	05DEC12	10DEC13
FDS20020	Fabric Filter Fabrication & Delivery - Sooner U2	300	25FEB13	23APR14
FDS20030	ID Booster Fan Fab & Delivery - Sooner U2	280	18MAR13	16APR14
FDS20040	Aux Transformer Fab & Delivery - Sooner U2	190	06AUG13	30APR14
FABRICATION / DELIVERY - MUSKOGEE U4				
FDM40010	DFGD Fabrication & Delivery - Muskogee U4	262	30MAY13	04JUN14
FDM40020	Fabric Filter Fab & Delivery - Muskogee U4	300	19AUG13	15OCT14
FDM40030	ID Booster Fan Fab & Delivery - Muskogee U4	280	09SEP13	08OCT14
FDM40040	Aux Transformer Fab & Delivery - Muskogee U4	190	29JAN14	22OCT14
FABRICATION / DELIVERY - MUSKOGEE U5				
FDM50010	DFGD Fabrication & Delivery - Muskogee U5	262	21NOV13	26NOV14
FDM50020	Fabric Filter Fab & Delivery - Muskogee U5	300	11FEB14	09APR15
FDM50030	ID Booster Fan Fab & Delivery - Muskogee U5	280	04MAR14	02APR15
FDM50040	Aux Transformer Fab & Delivery - Muskogee U5	190	23JUL14	16APR15
CONSTRUCTION CONTRACTS				
SLN1S20000	General Work Contract - Prep/Rvw/Award/Spec	85	08JUN12	05OCT12
CONSTRUCTION - SOONER U1				
CMS10010	General Work Contractor Mobilization - Sooner U1	10	22OCT12	02NOV12
CMS10020	U/G Utilities Relocation FGD Area - Sooner U1	45	05NOV12	08JAN13
CMS10030	DFGD Foundations - Sooner U1	80	24DEC12	16APR13
CMS10040	Structural Steel Installation - Sooner U1	100	16APR13	03SEP13
CMS10050	DFGD Erection and Startup - Sooner U1	300	22MAY13	21JUL14



Activity ID	Activity Description	Orig Dur	Start	Finish
CONSTRUCTION - SOONER U1				
CMS10060	ID Booster Fan Area Foundations - Sooner U1	90	24JUN13	28OCT13
CMS10070	Duckwork Installation - Sooner U1	150	15AUG13	14MAR14
CMS10080	Fabric Filter Erection - Sooner U1	145	30OCT13	22MAY14
CMS10090	ID Booster Fan Installation - Sooner U1	60	12NOV13	05FEB14
CMS10100	Electrical Installation - Sooner U1	160	05DEC13	21JUL14
CMS10110	Mechanical Installation - Sooner U1	140	06JAN14	21JUL14
CMS10120	Ductwork Erection ID Fan - Sooner U1	40	06FEB14	02APR14
START-UP - SOONER U1				
SUS10010	FGD Commissioning & Start Up - Sooner U1	140	08FEB14	21JUL14
SUS10020	Tie-in Outage - Sooner U1	37	09JUN14	21JUL14
SUS10030	DFGD in Service - Sooner U1	0		21JUL14
SUS10040	DFGD System Balancing / Performance Testing - S1	52	22JUL14	19SEP14
CONSTRUCTION - SOONER U2				
CMS20010	General Work Contractor Mobilization - Sooner U2	10	15APR13*	26APR13
CMS20020	U/G Utilities Relocation FGD Area - Sooner U2	45	29APR13	28JUN13
CMS20030	DFGD Foundations - Sooner U2	80	17JUN13	07OCT13
CMS20040	Structural Steel Installation - Sooner U2	100	07OCT13	25FEB14
CMS20050	DFGD Erection and Startup - Sooner U2	300	12NOV13	12JAN15
CMS20060	ID Booster Fan Area Foundations - Sooner U2	90	24DEC13	30APR14
CMS20070	Duckwork Installation - Sooner U2	150	20FEB14	18SEP14
CMS20080	Fabric Filter Erection - Sooner U2	145	24APR14	13NOV14
CMS20090	ID Booster Fan Installation - Sooner U2	60	15MAY14	07AUG14
CMS20100	Electrical Installation - Sooner U2	160	29MAY14	12JAN15
CMS20110	Mechanical Installation - Sooner U2	140	26JUN14	12JAN15
CMS20120	Ductwork Erection ID Fan - Sooner U2	40	08AUG14	02OCT14
START-UP - SOONER U2				
SUS20010	FGD Commissioning & Start Up - Sooner U2	140	02AUG14	12JAN15
SUS20020	Tie-in Outage - Sooner U2	37	01DEC14	12JAN15
SUS20030	DFGD in Service - Sooner U2	0		12JAN15
SUS20040	DFGD System Balancing / Performance Testing - S2	52	13JAN15	13MAR15
CONSTRUCTION - MUSKOGEE U4				
CMM40010	General Work Contractor Mobilization - Muskogee4	10	07OCT13*	18OCT13
CMM40020	U/G Utilities Relocation FGD Area - Muskogee U4	45	21OCT13	20DEC13



Activity ID	Activity Description	Orig Dur	Start	Finish
CONSTRUCTION - MUSKOGEE U4				
CMM40030	DFGD Foundations - Muskogee U4	80	09DEC13	01APR14
CMM40040	Structural Steel Installation - Muskogee U4	100	01APR14	19AUG14
CMM40050	DFGD Erection and Startup - Muskogee U4	300	07MAY14	06JUL15
CMM40060	ID Booster Fan Area Foundations - Muskogee U4	90	18JUN14	22OCT14
CMM40070	Duckwork Installation - Muskogee U4	150	14AUG14	13MAR15
CMM40080	Fabric Filter Erection - Muskogee U4	145	16OCT14	08MAY15
CMM40090	ID Booster Fan Installation - Muskogee U4	60	06NOV14	30JAN15
CMM40100	Electrical Installation - Muskogee U4	160	20NOV14	06JUL15
CMM40110	Mechanical Installation - Muskogee U4	140	18DEC14	06JUL15
CMM40120	Ductwork Erection ID Fan - Muskogee U4	40	02FEB15	27MAR15
START-UP - MUSKOGEE U4				
SUM40010	FGD Commissioning & Start Up - Muskogee U4	140	24JAN15	06JUL15
SUM40020	Tie-in Outage - Muskogee U4	37	25MAY15	06JUL15
SUM40030	DFGD in Service - Muskogee U4	0		06JUL15
SUM40040	DFGD System Balancing / Performance Testing - M4	52	07JUL15	04SEP15
CONSTRUCTION - MUSKOGEE U5				
CMM50010	General Work Contractor Mobilization - Muskogee5	10	01APR14*	14APR14
CMM50020	U/G Utilities Relocation FGD Area - Muskogee U5	45	15APR14	16JUN14
CMM50030	DFGD Foundations - Muskogee U5	80	03JUN14	23SEP14
CMM50040	Structural Steel Installation - Muskogee U5	100	23SEP14	11FEB15
CMM50050	DFGD Erection and Startup - Muskogee U5	300	29OCT14	28DEC15
CMM50060	ID Booster Fan Area Foundations - Muskogee U5	90	10DEC14	16APR15
CMM50070	Duckwork Installation - Muskogee U5	150	06FEB15	04SEP15
CMM50080	Fabric Filter Erection - Muskogee U5	145	10APR15	30OCT15
CMM50090	ID Booster Fan Installation - Muskogee U5	60	01MAY15	24JUL15
CMM50100	Electrical Installation - Muskogee U5	160	15MAY15	28DEC15
CMM50110	Mechanical Installation - Muskogee U5	140	12JUN15	28DEC15
CMM50120	Ductwork Erection ID Fan - Muskogee U5	40	27JUL15	18SEP15
START-UP - MUSKOGEE U5				
SUM50010	FGD Commissioning & Start Up - Muskogee U5	140	18JUL15	28DEC15
SUM50020	Tie-in Outage - Muskogee U5	37	16NOV15	28DEC15
SUM50030	DFGD in Service - Muskogee U5	0		28DEC15
SUM50040	DFGD System Balancing / Performance Testing - M5	52	29DEC15	26FEB16



Attachment B

Annualized Costs
Sooner Units 1 & 2
Muskogee Units 4 & 5

TABLE B-1
MUSKOGEE STATION UNIT 4
BART COST EVALUATION - DRY FGD (SDA) WORKSHEET

	INPUT	
	1 x 572 MW-gross	
Case	**PC Boiler**	
Gross Plant Output (MW-gross)	**572**	
Net Plant Output (MW-net)	**527**	Adjusted to account for additional auxiliary power.
Approximate Full Load Flue Gas Flow Rate (acfm)	**2,288,000**	
Maximum Heat Input (mmBtu/hr)	**5,480**	
Uncontrolled SO2 Emission Rate (lb/mmBtu)	**0.507**	
Post Dry FGD SO2 Emission Rate (lb/mmBtu)	**0.10**	
Capacity Factor used for Cost Estimates (%)	**90%**	

CAPITAL COSTS	**Muskogee Unit 4**		**Basis**
Direct Costs	$162,651,300		Based on Sargent & Lundy's conceptual cost estimating system. Direct costs include equipment, material, and labor; plus spare parts, special tools, consumables, and freight. Indirect costs include engineering, procurement, construction management, start-up, commissioning, operator training, and owner's costs.
Indirect Costs	$24,045,100		
Contingency	$30,200,900		
Total Plant Cost	$216,897,300		
Escalation	$30,622,900		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.
Allow. for Funds Used During Constr. (AFUDC)	$59,957,000		
Total Plant Investment (TPI)	$307,477,200		
Replacement Power Costs	$0		
Total Capital Requirement (TCR)	**$307,477,200**		
Total Capital Investment ($/kW - gross)	$538		
Capital Recovery Factor	0.1036		See derivation in Table 5.
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$31,854,600**		
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Lime Reagent Cost	$1,730,600	$ 105.53	Based on maximum heat input, SO2 removal rate (lb/hr), 0.90 stoichiometry, 90% CaO, 90% capacity factor, and $105.53/ton for lime.
Water Cost	$534,100	$ 2.57	Based on 219,839 lb/hr at full load, 90% capacity factor, and $2.57/1000 gal
FGD Waste Disposal Cost	$1,894,300	$ 40.59	Based on maximum heat input, SO2 removal rate (lb/hr), 90% capacity factor, and $40.59/ton on-site disposal cost. Disposal cost only includes FGD by-products and does not include fly ash.
Bag and Cage Replacement Costs	$675,100	$ 3.31	Based on the exhaust gas flow through the baghouse, air-to-cloth ratio of 3.5 for pulse jet baghouse, $3.31/ft2 bag cost (including fabric and hangers), 4% contingency for bag cleaning, and 3 year bag life.
Ash Disposal Costs	$0	$ 40.59	Assumed no increase in ash disposal with the fabric filter compared to the existing ESP control system.
Auxiliary Power Cost	$5,812,000	$ 85.92	Based on auxiliary power requirement of 1% (gross) for DFGD plus 0.5% (gross) for the baghouse, 90% capacity factor, and $85.92/MWh.
Total Variable O&M Costs	$10,646,100		
Fixed O&M Costs			
Additional Operators per shift	2.0		Based on S&L O&M estimate for dry FGD.
Operating Labor	$1,029,500	$ 58.76	3 shifts/day, 365 days/year @ 58.76/hour (salary + benefits) .
Supervisor Labor	$154,400	15.0%	of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$1,844,900	0.6%	Based on S&L experience on other FGD projects.
Maintenance Labor	$1,132,500	110.0%	of operating labor. EPA Control Cost Manual, page 2-31
Total Fixed O&M Cost	$4,161,300		
Indirect Operating Cost			
Property Taxes	$2,613,600	0.85%	Calculated as % of total capital investment (EPA Air Pollution Control Cost Manual 6th Ed., page 2-34). Administrative costs are 20% of Fixed O&M based on S&L experience on other projects.
Insurance	$32,200	0.0105%	
Administration	$832,300	20%	
Total Indirect Operating Cost	$3,478,100		
Total Annual Operating Cost	**$18,285,500**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$31,854,600**		
Annual Operating Cost	**$18,285,500**		
Total Annual Cost	**$50,140,100**		

TABLE B-2
MUSKOGEE STATION UNIT 5
BART COST EVALUATION - DRY FGD (SDA) WORKSHEET

Case	INPUT 1 x 572 MW-gross PC Boiler	
Gross Plant Output (MW-gross)	**572**	
Net Plant Output (MW-net)	**527**	Adjusted to account for additional auxiliary power.
Approximate Full Load Flue Gas Flow Rate (acfm)	**2,288,000**	
Maximum Heat Input (mmBtu/hr)	**5,480**	
Uncontrolled SO2 Emission Rate (lb/mmBtu)	**0.514**	
Post Dry FGD SO2 Emission Rate (lb/mmBtu)	**0.10**	
Capacity Factor used for Cost Estimates (%)	**90%**	

CAPITAL COSTS	**Muskogee Unit 5**		**Basis**
Direct Costs	$162,651,300		Based on Sargent & Lundy's conceptual cost estimating system. Direct costs include equipment, material, and labor; plus spare parts, special tools, consumables, and freight. Indirect costs include engineering, procurement, construction management, start-up, commissioning, operator training, and owner's costs.
Indirect Costs	$24,045,100		
Contingency	$30,200,900		
Total Plant Cost	$216,897,300		
Escalation	$30,622,900		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.
Allow. for Funds Used During Constr. (AFUDC)	$59,957,000		
Total Plant Investment (TPI)	$307,477,200		
Replacement Power Costs	$0		
Total Capital Requirement (TCR)	**$307,477,200**		
Total Capital Investment ($/kW - gross)	$538		
Capital Recovery Factor	0.1036		See derivation in Table 5.
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$31,854,600**		
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Lime Reagent Cost	$1,730,600	$ 105.53	Based on maximum heat input, SO2 removal rate (lb/hr), 0.90 stoichiometry, 90% CaO, 90% capacity factor, and $105.53/ton for lime.
Water Cost	$534,100	$ 2.57	Based on 219,839 lb/hr at full load, 90% capacity factor, and $2.57/1000 gal
FGD Waste Disposal Cost	$1,894,300	$ 40.59	Based on maximum heat input, SO2 removal rate (lb/hr), 90% capacity factor, and $40.59/ton on-site disposal cost. Disposal cost only includes FGD by-products and does not include fly ash.
Bag and Cage Replacement Costs	$675,100	$ 3.31	Based on the exhaust gas flow through the baghouse, air-to-cloth ratio of 3.5 for pulse jet baghouse, $3.31/ft2 bag cost (including fabric and hangers), 4% contingency for bag cleaning, and 3 year bag life.
Ash Disposal Costs	$0	40.59	Assumed no increase in ash disposal with the fabric filter compared to the existing ESP control system.
Auxiliary Power Cost	$5,812,000	$ 85.92	Based on auxiliary power requirement of 1% (gross) for DFGD plus 0.5% (gross) for the baghouse, 90% capacity factor, and $85.92/MWh.
Total Variable O&M Costs	$10,646,100		
Fixed O&M Costs			
Additional Operators per shift	2.0		Based on S&L O&M estimate for dry FGD.
Operating Labor	$1,029,500	$ 58.76	3 shifts/day, 365 days/year @ 58.76/hour (salary + benefits) .
Supervisor Labor	$154,400	15.0%	of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$1,844,900	0.6%	Based on S&L experience on other FGD projects.
Maintenance Labor	$1,132,500	110.0%	of operating labor. EPA Control Cost Manual, page 2-31
Total Fixed O&M Cost	$4,161,300		
Indirect Operating Cost			
Property Taxes	$2,613,600	0.85%	Calculated as % of total capital investment (EPA Air Pollution Control Cost Manual 6th Ed., page 2-34). Administrative costs are 20% of Fixed O&M based on S&L experience on other projects.
Insurance	$32,200	0.0105%	
Administration	$832,300	20%	
Total Indirect Operating Cost	$3,478,100		
Total Annual Operating Cost	**$18,285,500**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$31,854,600**		
Annual Operating Cost	**$18,285,500**		
Total Annual Cost	**$50,140,100**		

TABLE B-3
SOONER STATION UNIT 1
BART COST EVALUATION - DRY FGD (SDA) WORKSHEET

Case	INPUT 1 x 569 MW-gross PC Boiler	
Gross Plant Output (MW-gross)	**569**	
Net Plant Output (MW-net)	**524**	Adjusted to account for additional auxiliary power.
Approximate Full Load Flue Gas Flow Rate (acfm)	**2,276,000**	
Maximum Heat Input (mmBtu/hr)	**5,116**	
Uncontrolled SO2 Emission Rate (lb/mmBtu)	**0.509**	
Post Dry FGD SO2 Emission Rate (lb/mmBtu)	**0.10**	
Capacity Factor used for Cost Estimates (%)	**90%**	

CAPITAL COSTS	**Sooner Unit 1**		**Basis**
Direct Costs	$162,651,300		Based on Sargent & Lundy's conceptual cost estimating system. Direct costs include equipment, material, and labor; plus spare parts, special tools, consumables, and freight. Indirect costs include engineering, procurement, construction management, start-up, commissioning, operator training, and owner's costs.
Indirect Costs	$24,045,100		
Contingency	$29,336,700		
Total Plant Cost	$216,033,100		
Escalation	$23,301,500		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.
Allow. for Funds Used During Constr. (AFUDC)	$52,960,300		
Total Plant Investment (TPI)	$292,294,900		
Replacement Power Costs	$0		
Total Capital Requirement (TCR)	**$292,294,900**		
Total Capital Investment ($/kW - gross)	$514		
Capital Recovery Factor	0.1036		See derivation in Table 5.
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$30,281,800**		
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Lime Reagent Cost	$1,826,900	$ 118.80	Based on maximum heat input, SO2 removal rate (lb/hr), 0.90 stoichiometry, 90% CaO, 90% capacity factor, and $118.80/ton for lime.
Water Cost	$95,100	$ 0.49	Based on 205,256 lb/hr at full load, 90% capacity factor, and $0.49/1000 gal
FGD Waste Disposal Cost	$1,733,500	$ 39.60	Based on maximum heat input, SO2 removal rate (lb/hr), 90% capacity factor, and $39.60/ton on-site disposal cost. Disposal cost only includes FGD by-products and does not include fly ash.
Bag and Cage Replacement Costs	$653,300	$ 3.22	Based on the exhaust gas flow through the baghouse, air-to-cloth ratio of 3.5 for pulse jet baghouse, $3.22/ft2 bag cost (including fabric and hangers), 4% contingency for bag cleaning, and 3 year bag life.
Ash Disposal Costs	$0	$ 39.60	Assumed no increase in ash disposal with the fabric filter compared to the existing ESP control system.
Auxiliary Power Cost	$5,640,900	$ 83.83	Based on auxiliary power requirement of 1% (gross) for DFGD plus 0.5% (gross) for the baghouse, 90% capacity factor, and $83.83/MWh.
Total Variable O&M Costs	$9,949,700		
Fixed O&M Costs			
Additional Operators per shift	2.0	2	Based on S&L O&M estimate for dry FGD.
Operating Labor	$1,004,400	$ 57.33	3 shifts/day, 365 days/year @ 57.33/hour (salary + benefits) .
Supervisor Labor	$150,700	15.0%	of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$1,753,800	0.6%	Based on S&L experience on other FGD projects.
Maintenance Labor	$1,104,800	110.0%	of operating labor. EPA Control Cost Manual, page 2-31
Total Fixed O&M Cost	$4,013,700		
Indirect Operating Cost			
Property Taxes	$1,753,800	0.60%	Calculated as % of total capital investment (EPA Air Pollution Control Cost Manual 6th Ed., page 2-34). Administrative costs are 20% of Fixed O&M based on S&L experience on other projects.
Insurance	$30,600	0.0105%	
Administration	$802,700	20%	
Total Indirect Operating Cost	$2,587,100		
Total Annual Operating Cost	**$16,550,500**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$30,281,800**		
Annual Operating Cost	**$16,550,500**		
Total Annual Cost	**$46,832,300**		

TABLE B-4
SOONER STATION UNIT 2
BART COST EVALUATION - DRY FGD (SDA) WORKSHEET

Case	INPUT 1 x 569 MW-gross PC Boiler	
Gross Plant Output (MW-gross)	**569**	
Net Plant Output (MW-net)	**524**	Adjusted to account for additional auxiliary power.
Approximate Full Load Flue Gas Flow Rate (acfm)	**2,276,000**	
Maximum Heat Input (mmBtu/hr)	**5,116**	
Uncontrolled SO2 Emission Rate (lb/mmBtu)	**0.516**	
Post Dry FGD SO2 Emission Rate (lb/mmBtu)	**0.10**	
Capacity Factor used for Cost Estimates (%)	**90%**	

CAPITAL COSTS	**Sooner Unit 2**		**Basis**
Direct Costs	$162,651,300		Based on Sargent & Lundy's conceptual cost estimating system. Direct costs include equipment, material, and labor; plus spare parts, special tools, consumables, and freight. Indirect costs include engineering, procurement, construction management, start-up, commissioning, operator training, and owner's costs.
Indirect Costs	$24,045,100		
Contingency	$29,336,700		
Total Plant Cost	$216,033,100		
Escalation	$23,301,500		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.
Allow. for Funds Used During Constr. (AFUDC)	$52,960,300		
Total Plant Investment (TPI)	$292,294,900		
Replacement Power Costs	$0		
Total Capital Requirement (TCR)	**$292,294,900**		
Total Capital Investment ($/kW - gross)	$514		
Capital Recovery Factor	0.1036		See derivation in Table 5.
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$30,281,800**		
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Lime Reagent Cost	$1,826,900	$ 118.80	Based on maximum heat input, SO2 removal rate (lb/hr), 0.90 stoichiometry, 90% CaO, 90% capacity factor, and $118.80/ton for lime.
Water Cost	$95,100	$ 0.49	Based on 205,256 lb/hr at full load, 90% capacity factor, and $0.49/1000 gal
FGD Waste Disposal Cost	$1,733,500	$ 39.60	Based on maximum heat input, SO2 removal rate (lb/hr), 90% capacity factor, and $39.60/ton on-site disposal cost. Disposal cost only includes FGD by-products and does not include fly ash.
Bag and Cage Replacement Costs	$653,300	$ 3.22	Based on the exhaust gas flow through the baghouse, air-to-cloth ratio of 3.5 for pulse jet baghouse, $3.22/ft2 bag cost (including fabric and hangers), 4% contingency for bag cleaning, and 3 year bag life.
Ash Disposal Costs	$0	$ 39.60	Assumed no increase in ash disposal with the fabric filter compared to the existing ESP control system.
Auxiliary Power Cost	$5,640,900	$ 83.83	Based on auxiliary power requirement of 1% (gross) for DFGD plus 0.5% (gross) for the baghouse, 90% capacity factor, and $83.83/MWh.
Total Variable O&M Costs	$9,949,700		
Fixed O&M Costs			
Additional Operators per shift	2.0	2	Based on S&L O&M estimate for dry FGD.
Operating Labor	$1,004,400	$ 57.33	3 shifts/day, 365 days/year @ 57.33/hour (salary + benefits) .
Supervisor Labor	$150,700	15.0%	of operating labor. EPA Control Cost Manual, page 2-31
Maintenance Materials	$1,753,800	0.6%	Based on S&L experience on other FGD projects.
Maintenance Labor	$1,104,800	110.0%	of operating labor. EPA Control Cost Manual, page 2-31
Total Fixed O&M Cost	$4,013,700		
Indirect Operating Cost			
Property Taxes	$1,753,800	0.60%	Calculated as % of total capital investment (EPA Air Pollution Control Cost Manual 6th Ed., page 2-34). Administrative costs are 20% of Fixed O&M based on S&L experience on other projects.
Insurance	$30,600	0.0105%	
Administration	$802,700	20%	
Total Indirect Operating Cost	$2,587,100		
Total Annual Operating Cost	**$16,550,500**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$30,281,800**		
Annual Operating Cost	**$16,550,500**		
Total Annual Cost	**$46,832,300**		

Table B-5
Annual and Levelized Capital Charges
Real Rates Excluding Inflation

Calendar Year		**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Operating Year		1	2	3	4	5	6	7	8	9	10	11	12
Tax Depreciation		5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%
Debt Balance		44,300,000	42,085,000	39,870,000	37,655,000	35,440,000	33,225,000	31,010,000	28,795,000	26,580,000	24,365,000	22,150,000	19,935,000
Equity Balance		55,700,000	52,915,000	50,130,000	47,345,000	44,560,000	41,775,000	38,990,000	36,205,000	33,420,000	30,635,000	27,850,000	25,065,000
	Levelized Values												
Capital Recovery	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
Debt Return	932,578	1,525,649	1,449,366	1,373,084	1,296,801	1,220,519	1,144,237	1,067,954	991,672	915,389	839,107	762,824	686,542
Equity Return	2,740,413	4,483,171	4,259,012	4,034,854	3,810,695	3,586,537	3,362,378	3,138,220	2,914,061	2,689,902	2,465,744	2,241,585	2,017,427
Income Taxes	1,688,180	2,761,772	2,623,684	2,485,595	2,347,506	2,209,418	2,071,329	1,933,241	1,795,152	1,657,063	1,518,975	1,380,886	1,242,798
Property Taxes and Insurance	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Charges	10,361,171	13,770,592	13,332,062	12,893,533	12,455,003	12,016,473	11,577,944	11,139,414	10,700,885	10,262,355	9,823,825	9,385,296	8,946,766
Annual Rate (% of initial capital investment)		13.77%	13.33%	12.89%	12.46%	12.02%	11.58%	11.14%	10.70%	10.26%	9.82%	9.39%	8.95%
Levelized Rate	10.36%												

Income Statement (Check)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Revenue Requirements	13,770,592	13,332,062	12,893,533	12,455,003	12,016,473	11,577,944	11,139,414	10,700,885	10,262,355	9,823,825	9,385,296	8,946,766
Property Taxes and Insurance	0	0	0	0	0	0	0	0	0	0	0	0
EBITDA	13,770,592	13,332,062	12,893,533	12,455,003	12,016,473	11,577,944	11,139,414	10,700,885	10,262,355	9,823,825	9,385,296	8,946,766
Depreciation	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
EBIT	8,770,592	8,332,062	7,893,533	7,455,003	7,016,473	6,577,944	6,139,414	5,700,885	5,262,355	4,823,825	4,385,296	3,946,766
Interest	1,525,649	1,449,366	1,373,084	1,296,801	1,220,519	1,144,237	1,067,954	991,672	915,389	839,107	762,824	686,542
EBT	7,244,943	6,882,696	6,520,449	6,158,202	5,795,954	5,433,707	5,071,460	4,709,213	4,346,966	3,984,719	3,622,472	3,260,224
Income Taxes												
Cash	2,761,772	2,623,684	2,485,595	2,347,506	2,209,418	2,071,329	1,933,241	1,795,152	1,657,063	1,518,975	1,380,886	1,242,798
Deferred	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,761,772	2,623,684	2,485,595	2,347,506	2,209,418	2,071,329	1,933,241	1,795,152	1,657,063	1,518,975	1,380,886	1,242,798
Net Income	4,483,171	4,259,012	4,034,854	3,810,695	3,586,537	3,362,378	3,138,220	2,914,061	2,689,902	2,465,744	2,241,585	2,017,427
Equity Return (Check)	4,483,171	4,259,012	4,034,854	3,810,695	3,586,537	3,362,378	3,138,220	2,914,061	2,689,902	2,465,744	2,241,585	2,017,427
Tax Calculations:												
EBITDA	13,770,592	13,332,062	12,893,533	12,455,003	12,016,473	11,577,944	11,139,414	10,700,885	10,262,355	9,823,825	9,385,296	8,946,766
Tax Depreciation	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
EBIT	8,770,592	8,332,062	7,893,533	7,455,003	7,016,473	6,577,944	6,139,414	5,700,885	5,262,355	4,823,825	4,385,296	3,946,766
Interest	1,525,649	1,449,366	1,373,084	1,296,801	1,220,519	1,144,237	1,067,954	991,672	915,389	839,107	762,824	686,542
EBT	7,244,943	6,882,696	6,520,449	6,158,202	5,795,954	5,433,707	5,071,460	4,709,213	4,346,966	3,984,719	3,622,472	3,260,224
Taxes	2,761,772	2,623,684	2,485,595	2,347,506	2,209,418	2,071,329	1,933,241	1,795,152	1,657,063	1,518,975	1,380,886	1,242,798
Rate Base - Year Begin	100,000,000	95,000,000	90,000,000	85,000,000	80,000,000	75,000,000	70,000,000	65,000,000	60,000,000	55,000,000	50,000,000	45,000,000
Book Depreciation	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
Deferred Taxes	0	0	0	0	0	0	0	0	0	0	0	0
Net Book	95,000,000											
Rate Base - Year End	95,000,000	90,000,000	85,000,000	80,000,000	75,000,000	70,000,000	65,000,000	60,000,000	55,000,000	50,000,000	45,000,000	40,000,000

Table B-5
Annual and Levelized Capital Charges
Real Rates Excluding Inflation

Calendar Year		**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Operating Year		13	14	15	16	17	18	19	20
Tax Depreciation		5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%
Debt Balance		17,720,000	15,505,000	13,290,000	11,075,000	8,860,000	6,645,000	4,430,000	2,215,000
Equity Balance		22,280,000	19,495,000	16,710,000	13,925,000	11,140,000	8,355,000	5,570,000	2,785,000
	Levelized Values								
Capital Recovery	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
Debt Return	932,578	610,260	533,977	457,695	381,412	305,130	228,847	152,565	76,282
Equity Return	2,740,413	1,793,268	1,569,110	1,344,951	1,120,793	896,634	672,476	448,317	224,159
Income Taxes	1,688,180	1,104,709	966,620	828,532	690,443	552,354	414,266	276,177	138,089
Property Taxes and Insurance	0	0	0	0	0	0	0	0	0
Total Capital Charges	10,361,171	8,508,237	8,069,707	7,631,178	7,192,648	6,754,118	6,315,589	5,877,059	5,438,530
Annual Rate (% of initial capital investment)		8.51%	8.07%	7.63%	7.19%	6.75%	6.32%	5.88%	5.44%
Levelized Rate	10.36%								
Income Statement (Check)									
Revenue Requirements		8,508,237	8,069,707	7,631,178	7,192,648	6,754,118	6,315,589	5,877,059	5,438,530
Property Taxes and Insurance		0	0	0	0	0	0	0	0
EBITDA		8,508,237	8,069,707	7,631,178	7,192,648	6,754,118	6,315,589	5,877,059	5,438,530
Depreciation		5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
EBIT		3,508,237	3,069,707	2,631,178	2,192,648	1,754,118	1,315,589	877,059	438,530
Interest		610,260	533,977	457,695	381,412	305,130	228,847	152,565	76,282
EBT		2,897,977	2,535,730	2,173,483	1,811,236	1,448,989	1,086,741	724,494	362,247
Income Taxes									
Cash		1,104,709	966,620	828,532	690,443	552,354	414,266	276,177	138,089
Deferred		0	0	0	0	0	0	0	0
Total		1,104,709	966,620	828,532	690,443	552,354	414,266	276,177	138,089
Net Income		1,793,268	1,569,110	1,344,951	1,120,793	896,634	672,476	448,317	224,159
Equity Return (Check)		1,793,268	1,569,110	1,344,951	1,120,793	896,634	672,476	448,317	224,159
Tax Calculations:									
EBITDA		8,508,237	8,069,707	7,631,178	7,192,648	6,754,118	6,315,589	5,877,059	5,438,530
Tax Depreciation		5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
EBIT		3,508,237	3,069,707	2,631,178	2,192,648	1,754,118	1,315,589	877,059	438,530
Interest		610,260	533,977	457,695	381,412	305,130	228,847	152,565	76,282
EBT		2,897,977	2,535,730	2,173,483	1,811,236	1,448,989	1,086,741	724,494	362,247
Taxes		1,104,709	966,620	828,532	690,443	552,354	414,266	276,177	138,089
Rate Base - Year Begin		40,000,000	35,000,000	30,000,000	25,000,000	20,000,000	15,000,000	10,000,000	5,000,000
Book Depreciation		5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000
Deferred Taxes		0	0	0	0	0	0	0	0
Net Book									
Rate Base - Year End		35,000,000	30,000,000	25,000,000	20,000,000	15,000,000	10,000,000	5,000,000	0

Attachment C

BART Comparison Table

BART Cost Evaluation
SO_2 Control

Technology		Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	
Station		MUSKOGEE STATION	MUSKOGEE STATION	SOONER STATION	SOONER STATION	GERALD GENTLEMAN	GERALD GENTLEMAN	WHITE BLUFF	WHITE BLUFF	BOARDMAN	NORTHEASTERN	NORTHEASTERN	NAUGHTON	NAUGHTON	NEBRASKA CITY	
Unit		UNIT 4	UNIT 5	UNIT 1	UNIT 2	UNIT 1	UNIT 2	UNIT 1	UNIT 2	UNIT 1	UNIT 3	UNIT 4	UNIT 1	UNIT 2	UNIT 1	Remarks
Date		December 2009	December 2009	December 2009	December 2009	March 2008	March 2008	August 2008	August 2008	November 2007	May 2008	May 2008	December 2007	December 2007	August 2007	
Rating (gross)	MW	572	572	569	569	750	750	850	850	617	493	493	176	234		Northeastern - calculated from $/kW values
Rating (net)	MW	527	527	524	524	665	700	844	844	584	470	470	160	210	650	
Heat Input:	mmBtu/hr	5,480	5,480	5,116	5,116	7,393	7,782	9,339	10,221	5,793	4,775	4,775	1,850	2,400	6,776.8	Boardman - highest rolling 12 month data - worst case Naughton - measured by CEMS
Capacity Factor	%	90%	90%	90%	90%	100%	100%	85%	85%	85%	85%	85%	90%	90%	100%	
Maximum Hours/year:	hours/yr	7,884	7,884	7,884	7,884	8,760	8,760	7,446	7,446	7,446	7,446	7,446	7,884	7,884	8,760	
Capital Cost Recovery Factor Equipment Life	years	20	20	20	20	20	20	40	40	20	20	20	20	20	20	
Interest Rate	%	5.43%	5.43%	5.43%	5.43%	5.25%	5.25%	7.67%	7.67%	7%	8%	8%	7.1%	7.1%	5.0%	OG&E - weighted after cost of capital (real)
Capital Cost Recovery Factor		0.1036	0.1036	0.1036	0.1036	0.0820	0.0820	0.0809	0.0809	0.0944	0.1019	0.1019	0.0951	0.0951	0.0802	Calculated based on equipment life and interest rate OG&E - levelized over 20 years, includes taxes on liability associated wit including DFGD in OG&E's rate bas
Energy Impact	% or MW	1.5%	1.5%	1.5%	1.5%	13 MW	13 MW	11.4 MW	11.4 MW	4,088 kW	Not specified in BART	Not specified in BART	1.66% or 2.66 MW	1.73% or 3.63 MW	1% or 6 MW	
Fuel		Subbituminous coa	Subbituminous coa	Subbituminous coa	Subbituminous coa	Subbituminous coa	Subbituminous coa	Subbituminous coa	Subbituminous coa	Low sulfur PRB	Western sub-bituminou	Western sub-bituminou	Subbituminous coa	Subbituminous coa	Western subbituminous coa	
Fuel Sulfur Conten	%	0.20 - 0.37	0.20 - 0.37	0.20 - 0.37	0.20 - 0.37	0.7	0.7	0.78	0.73	0.17 - 1.00	0.45 - 0.49	0.45 - 0.49	0.58 or 1.02	0.58 or 1.02	0.34	Northeastern - calculated based on baseline SO2 emissions (lb/hr) and coa usage (tpy) White Bluff - based on calculated uncontrolled SO2 emission rate and assumed coal heating value of 8500 Btu/lb Nebraska City - based on 0.815 lb SO2/mmBtu, 8400 Btu/l
EMISSIONS																
BART Baseline Uncontrolled SO_2 Emission Rate	lb/mmBtu	0.507	0.514	0.509	0.516	0.749	0.749	0.915	0.854	0.614	0.900	0.900	1.180	1.180	0.815	OG&E - based on 3-year average emission from 2004-200 Gerald Gentleman - maximum 24 hour emissions from 2001-2003 data White Bluff - calculated based on information provided in Table A-1 of BART Report Boardman - highest rolling 12 month total betw 2003-2005 Naughton - based on average 0.58% sulfur in coal Nebraska City - maximum actual 24-hour emissions over 3-year baseline period
BART Baseline Annual SO_2 Emissions	ton/year	9,113	9,006	9,394	8,570	24,254	25,531	31,806	32,510	14,902	16,000	16,000	8,624	11,187	24,191	Calculation methods vary
Expected SO_2 Emission Rate	lb/mmBtu	0.10	0.10	0.10	0.10	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	Naughton - based on 0.58% sulfur in coal
Expected SO_2 Emissions	ton/year	2,160	2,160	2,017	2,017	4,857	5,113	5,215	5,708	3,643	2,720	2,720	1,094	1,419	4,452	Calculation methods vary.
Expected SO_2 Emissions Reduction	ton/year	6,953	6,846	7,377	6,553	19,397	20,418	26,591	26,802	11,259	13,280	13,280	7,530	9,768	19,739	Gerald Gentleman reduction based on worst case
SO_2 Removal	%	80.3%	80.5%	80.4%	80.6%	80.0%	80.0%	83.6%	82.4%	75.6%	83.0%	83.0%	87.3%	87.3%	81.6%	
Visibility Improvement - Sum of Class I Areas	Δdv	4.217		2.440		Not Available		Not Available		9.842	3.670		1.904	2.176	1.244	Sum of visibility improvements at all surrounding Class I areas Gerald Gentleman - only worst case provided - page 47 of BART White Bluff - only worst case provided - page 5-1 of BAR
Visibility Improvement - Single Class I Areas	Δdv	1.275		1.170		0.641		3.587		0.969	1.050		1.243	1.358	0.437	Sum of visibility improvements at all surrounding Class I areas Gerald Gentleman - only worst case provided - page 47 of BART White Bluff - only worst case provided - page 5-1 of BAR
COSTS																
Total Capital Cost Investment	$	307,477,200	307,477,200	292,294,900	292,294,900	486,188,000	495,404,000	353,448,500	353,448,500	247,293,000	273,350,000	273,350,000	108,995,970	141,244,778	201,660,000	White Bluff - includes indirect expenses, escalation, sales tax, continency AFUDC Gerald Gentleman/Naughton - includes contingency, labor premium, EPC premium, boiler reinforcement, sales tax, escalation, contingency on adders, surcharge and AFUDC
Capital Cost per kW (gross)	$/kw	538	538	514	514	731	708	419	419	401	555	555	681	673	310	Gerald Gentleman/White Bluff/Naughton/Nebraska City - based on MW
Annual Capital Recovery Costs	$/year	31,854,600	31,854,600	30,281,800	30,281,800	38,980,692	41,032,308	51,655,000	51,655,000	23,344,000	27,841,302	27,841,302	10,368,549	13,436,308	16,180,000	Based on capital cost recovery factor
Annual Operating Costs	$/year	18,285,500	18,285,500	16,550,500	16,550,500	13,826,000	13,980,000	13,500,000	13,500,000	12,978,000	15,535,100	15,535,100	4,749,236	6,234,767	18,540,000	OG&E - includes Fixed O&M, Variable O&M, Indirect Northeastern - includes Variable O&M, Indirects Gerald Gentleman/White Bluff/Boardman/Naughton - includes Fixed O&M, Variable O&M
Total Annual Costs	$/year	50,140,100	50,140,100	46,832,300	46,832,300	53,146,692	55,370,308	65,155,000	65,155,000	36,322,000	43,376,402	43,376,402	15,117,785	19,671,075	34,720,000	
Average Annual Cost Effectivenes	$/ton	7,211	7,324	6,348	7,147	2,740	2,712	2,450	2,431	3,226	3,266	3,266	2,008	2,014	1,759	Gerald Gentleman effectiveness based on worst case emissions. About $4783 if calculated consistent with OG&E. Naughton - values in BART based on first year cost so doesn't match th
Incremental Impairment Improvement Cost - Sum of Class I Areas	$/yr/dv	23,779,986		38,387,131		Don't have necessary Δdv data		Don't have necessary Δdv data		3,690,510	23,638,366		7,940,013	9,040,016	27,909,968	Calculated based on visibility improvement in all affected Class I areas (not just area with greatest impact)
Incremental Impairment Improvement Cost - Single Class I Area	$/yr/dv	78,651,137		80,055,214		169,189,000		39,260,000		37,484,004	82,621,717		12,304,899	14,500,042	79,450,801	Calculated based on visibility improvement in Class I area with greatest impact Gerald Gentleman - pg 47 of BART White Bluff - pg 5-1 of BART, includes tuning, OFA, LNB, dry scrubbing Naughton - pg 4-12 of BART, includes LNB with OFA Nebraska City - pg 12 of BART Fact Sheet (NDEQ)

BART Cost Evaluation
SO_2 Control

Technology		Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	Dry FGD-SDA/FF	
Station		MUSKOGEE STATION	MUSKOGEE STATION	SOONER STATION	SOONER STATION	GERALD GENTLEMAN	GERALD GENTLEMAN	WHITE BLUFF	WHITE BLUFF	BOARDMAN	NORTHEASTERN	NORTHEASTERN	NAUGHTON	NAUGHTON	NEBRASKA CITY	
Unit		UNIT 4	UNIT 5	UNIT 1	UNIT 2	UNIT 1	UNIT 2	UNIT 1	UNIT 2	UNIT 1	UNIT 3	UNIT 4	UNIT 1	UNIT 2	UNIT 1	Remarks
ANNUAL COST																
O&M Costs - TOTAL		**14,807,400**	**14,807,400**	**13,963,400**	**13,963,400**	**13,826,000**	**13,980,000**	**13,500,000**	**13,500,000**	**12,978,000**	**4,601,100**	**4,601,100**	**4,749,236**	**6,234,767**	**18,540,000**	
Fixed O&M - TOTAL	$/year	**4,161,300**	**4,161,300**	**4,013,700**	**4,013,700**	**3,906,000**	**3,906,000**	**3,550,000**	**3,550,000**	**4,709,000**	**0**	**0**	**1,894,521**	**2,432,517**	**2,120,300**	
Maintenance (Mat + Labor)	$/year	2,977,400	2,977,400	2,858,600	2,858,600	2,911,000	2,911,000	Incl. above	Incl. above	4,409,000	---	---	Incl. above	Incl. above	1,704,300	OG&E - 0.6% of PEC, 110% of operating labor White Bluff - 0.065% of initial capital cost Boardman - 3% of capital cost per year Nebraska City - 1.5% of cost
Operating (Labor)	$/year	1,183,900	1,183,900	1,155,100	1,155,100	995,000	995,000	Incl. above	Incl. above	300,000	---	---	Incl. above	Incl. above	416,000	OG&E - 2 additional operators, includes supervision (15% of labor), 3 shifts/day, $57.33/hr salary + benefits (Sooner), $58.76/hr salary + benefits (Muskogee) White Bluff - $40/hr, 16 additional full time staff Boardman - $100,000/yr per person Nebraska City - 4 operators, $50/hr
Variable O&M - TOTAL	$/year	**10,646,100**	**10,646,100**	**9,949,700**	**9,949,700**	**9,920,000**	**10,074,000**	**9,950,000**	**9,950,000**	**8,269,000**	**4,601,100**	**4,601,100**	**2,854,715**	**3,802,250**	**8,365,000**	
Lime	$/year	1,730,600	1,730,600	1,826,900	1,826,900	7,316,000	7,420,000	Incl. above	Incl. above	4,915,000	3,090,000	3,090,000	926,526	1,201,979	2,946,000	Muskogee - $105.53/ton lime Sooner - $118.80/ton lime Gerald Gentleman - $95/ton delivered White Bluff - $107/ton, 1.1 SR Boardman - $132/ton Northeastern - $200/ton lime Naughton - $91.25/ton lime, 1.15 SR Nebraska City - $125/ton lime delivered
Water	$/year	534,100	534,100	95,100	95,100	483,000	499,000	Incl. above	Incl. above	300,000	---	---	81,874	112,577	---	Muskogee - $2.57/1000 gal Sooner - $0.49/1000 gal Gerald Gentleman - $1.00/1000 gal White Bluff - 1050 gpm per unit, $0.92/1000 gal makeup water Boardman - 336 gpm, $2/1000 gal makeup water Naughton - 120 gpm, $1.22/1000 gal
Solid FGD Waste	$/year	1,894,300	1,894,300	1,733,500	1,733,500	1,620,000	1,643,000	Incl. above	Incl. above	742,000	---	---	496,582	644,215	509,000	Muskogee - $40.59/ton on-site disposal Sooner - $39.60/ton on-ste disposal Gerald Gentleman - $5/ton White Bluff - $8.58/ton Boardman - $10/ton Naughton - $24.33/ton Nebraska City - $9/ton
Fly Ash Disposal	$/year	0	0	0	0	---	---	---	---	---	---	---	---	---	---	OG&E - assume no increase compared to current ESP fly ash
Bags and Cages	$/year	675,100	675,100	653,300	653,300	---	---	Incl. above	Incl. above	790,000	---	---	106,648	147,088	360,000	Muskogee - $3.31/ft^2 bag, 3 year bag life Sooner - $3.22/ft^2 bag, 3 year bag life White Bluff - $110/bag Boardman - $100/bag, $50/cage Naughton - $104/bag Nebraska City - $100/bag, 5 year bag life
Sales of Allowances	$/year	0	0	0	0	-4,755,000	-4,744,000	---	---	---	---	---	---	---	---	
Auxiliary Power	$/year	5,812,000	5,812,000	5,640,900	5,640,900	5,256,000	5,256,000	Incl. above	Incl. above	1,522,000	1,511,100	1,511,100	1,243,085	1,696,391	4,550,000	Muskogee - $85.92/MWh Sooner - $83.83/MWh Gerald Gentleman - $45.65/MWh, includes energy charge and capacity charge White Bluff - $47/MWh Boardman/Northeastern/Naughton - $50/MWh Nebraska City - $30/MWh, $0.46/MW
Extended Outage Power Purc.	$/year	**0**	**0**	**0**	**0**	**340,000**	**358,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	Gerald Gentleman - $31.90/MWh Nebraska City - $30/MWh
Indirect Costs	$/year	**3,478,100**	**3,478,100**	**2,587,100**	**2,587,100**	**0**	**0**	**0**	**0**	**0**	**10,934,000**	**10,934,000**	**0**	**0**	**0**	Gerald Gentleman/White Bluff/Boardman/Naughton - Not included in estimate
Property Taxes	$/year	2,613,600	2,613,600	1,753,800	1,753,800	---	---	---	---	---	2,733,500	2,733,500	---	---	---	Muskogee - 0.85% of total capital investment Sooner - 0.6% of total capital investment Northeastern - 1% total capital investment
Insurance	$/year	32,200	32,200	30,600	30,600	---	---	---	---	---	2,733,500	2,733,500	---	---	---	OG&E - 0.0105% of total capital investment Northeastern- 1% total capital investment
Administration	$/year	832,300	832,300	802,700	802,700	---	---	---	---	---	5,467,000	5,467,000	---	---	---	OG&E - 20% of fixed O&M Northeastern - 2% total capital investment
Fixed Charges on Investment	$/year	**31,854,600**	**31,854,600**	**30,281,800**	**30,281,800**	**38,980,692**	**41,032,308**	**51,655,000**	**51,655,000**	**23,344,000**	**27,841,302**	**27,841,302**	**10,368,549**	**13,436,308**	**16,180,000**	
Annual Cost	$/year	**50,140,100**	**50,140,100**	**46,832,300**	**46,832,300**	**53,146,692**	**55,370,308**	**65,155,000**	**65,155,000**	**36,322,000**	**43,376,402**	**43,376,402**	**15,117,785**	**19,671,075**	**34,720,000**	

Exhibit 4

Charles T. Wehland/JonesDay
Extension 312 269 4388
(54388)

11/17/2009 11:33 AM

To smith.suzanne@epa.gov
cc
bcc
Subject Fw: OG&E BART Presentation

Suzanne,

Thanks for meeting with OG&E earlier this month. The message that I sent to Joe with a copy of the presentation is attached.

We asked Joe for a reference to the FLM study that he mentioned during the meeting, but we have not had a response. It would be useful to have the information because OG&E is meeting with the FLM on Dec. 7.

Thank you in advance for any help you can provide with this.

* * * Chuck Wehland - 312 269 4388 * * *

----- Forwarded by Charles T. Wehland/JonesDay on 11/17/2009 10:30 AM -----

Charles T. Wehland/JonesDay
Extension 312 269 4388
(54388)

11/03/2009 04:12 PM

To kordzi.joe@epa.gov
cc shoopkl@oge.com, "David Branecky" <branecda@oge.com>, brockmcd@oge.com, paul.r.predick@sargentlundy.com
Subject OG&E BART Presentation

Joe,

An electronic copy of the presentation made at the meeting today on the OG&E regional haze proposal and BART determination is attached. We appreciated the open exchange of information at the meeting.

During the meeting, you mentioned a FLM study that indicated an average SO_2 cost effectiveness of $2,600 per ton. Can you give me a reference to where we can find that study?

We will be in touch as we work through the process of gathering additional information for DEQ. Please do not hesitate to let any of us know if there is information that EPA believes would be helpful.

Thank you.

* * * Chuck Wehland - 312 269 4388 * * *

CHI_1725138_3_BART Presentation.PPT

==========

Exhibit 5

Factors Affecting Cost Effectiveness Estimates for Dry FGD at OG&E Units and Other Facilities

Facility	MW gross	Fuel Sulfur Content	Max Heat Input Per Unit (mmBtu/hr)	Baseline Emissions Rate (lb/mmBtu)	Total Annual Cost Per Unit	TPY Removed Per Unit	Assumed Control Effectiveness of (% SO_2 removal)	Average Annual Cost Effectiveness ($/ton)
White Bluff Units 1-2	850	0.87%	9,339 – 10,221	Max 24-hour 2001-2003 (0.854-0.915)	$65.1M	26,591 - 26,802	82.4% - 83.6%	$2,431 - $2,450
NCS Unit 1	650 (net)	0.34%	6,776	Max 24-hour from baseline period (0.815)	$34.7M	19,739	81.6%	$1,759
GGS Units 1-2	750	0.7%	7,393-7,782	Max 24-hour 2001-2003 (0.749)	$53.1M-55.3M	19,397-20,418	80.0%	$2,712 - $2,740
Boardman Unit 1	617	0.17 - 1.00%	5,793	Highest rolling 12-mo. 2003-2005 (0.614)	$36.3M	11,259	75.6%[1]	$3,226
Northeastern Units 3-4	493	0.45 - 0.49%	4,775	Max 24-hour from 2002-2005 (0.90)	$43.4M	13,280	83.0%	$3,266
OG&E May 2008 and Sept. 2009 Data								
Sooner Units 1 and 2	569	0.20 - 0.37%	5,116	Annual ave. 2004-2006 (0.509-0.516)	$71.0M	6,553 - 7,377	80.4% - 80.6%	$9,625 - $10,843
Muskogee Units 4 and 5	572	0.20 - 0.37%	5,480	Annual ave. 2004-2006 (0.507-0.514)	$68.4M	6,846 – 6,953	80.3% - 80.5%	$9,842 - $10,004
OG&E December 2009 Data								
Sooner Units 1 and 2	569	0.20 - 0.37%	5,116	3-year ave. 2004-2006 (0.509-0.516)	$46.8M	6,553 - 7,377	80.4% - 80.6%	$6,348 - $7,147
Muskogee Units 4 and 5	572	0.20 - 0.37%	5,480	3-year ave. 2004-2006 (0.507-0.514)	$50.1M	6,846 – 6,953	80.3% - 80.5%	$7,211 - $7,324

[1] This is Portland General Electric's (PG&E) estimate. The Oregon Department of Environmental Quality decided control effectiveness should not be evaluated based on a percent reduction because Boardman already burns low-sulfur coal, and its current SO_2 emission rate is about 0.6 lb/mmBtu. To meet a 90% emission reduction, emissions at the outlet of the control device would need to be 0.06 lb/mmBtu. ODEQ thought this rate was not achievable at the best performing units with similar control devices. *See* ODEQ BART Report for Boardman at 17, http://www.deq.state.or.us/aq/haze/docs/deqBartReport.pdf.

References

- OG&E BART Analyses for Muskogee and Sooner Generating Stations (May 2008)
- Sargent and Lundy BART Cost Effectiveness Update for Sooner and Muskogee Generating Stations (Sept. 17, 2009)
- Revised BART Analysis for White Bluff (Aug. 2008)
- BART Analysis for Nebraska City Station (NCS) Unit 1 (Aug. 2007), available at http://www.deq.state.ne.us/AirDivis.nsf/Pages/Haze
- Revised BART Analysis for Gerald Gentleman Station Units 1 and 2 (Feb. 2008), available at http://www.deq.state.ne.us/AirDivis.nsf/Pages/Haze
- Portland General Electric BART Analysis for Boardman Power Plant (Nov. 2, 2007), available at http://blog.oregonlive.com/breakingnews/2007/11/boardman.pdf
- ODEQ BART Report for Boardman Power Plant (Dec. 19, 2008), available at http://www.deq.state.or.us/aq/haze/docs/deqBartReport.pdf.

Exhibit 6

DRAFT

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **October 27, 2009**

TO:	Phillip Fielder, P.E., Permits and Engineering Group Manager Air Quality Division
THROUGH:	Kendal Stegmann, Senior Environmental Manager Compliance and Enforcement
THROUGH:	Phil Martin, P.E., Engineering Section
THROUGH:	Peer Review
FROM:	Eric L. Milligan, P.E., Engineering Section
SUBJECT:	Evaluation of Permit Application No. **2003-400-TVR (M-1)** Oklahoma Gas & Electric Company Seminole Generating Station (4911) Section 25, T6N, R5E, Seminole County Latitude: 34.9705°N; Longitude: 96.7335°W Located Two Miles Northeast of Konawa

SECTION I. INTRODUCTION

The Oklahoma Gas & Electric Company (OG&E) has requested a modification of their current Part 70 operating permit to incorporate the proposed BART analysis and requirements. The facility is currently operating under Permit No. 2003-400-TVR issued May 9, 2006.

SECTION II. FACILITY DESCRIPTION

The Seminole facility consists of three (3) natural circulation Babcock and Wilcox El-Paso type boilers capable of producing steam. The thermodynamic energy in the steam is converted to mechanical energy and then to electrical energy by the steam turbine/generator unit capable of producing electricity. Both Unit 1 and Unit 2 boilers use natural gas as their primary fuel and are capable of using #2 fuel oil as a secondary fuel. The fuel oil is stored in two (2) 55,000-barrel storage tanks and is fed into the boilers by pipeline. Unit 3 boiler uses natural gas as its primary fuel and #6 fuel oil as secondary fuel. The #6 fuel oil is stored in one (1) 300,000-barrel storage tank, transferred to a 126,000 gallon surge tank and is fed into the boiler by pipeline.

The facility utilizes a gas-fired auxiliary boiler to provide steam for heating the #6 fuel oil. The boiler has a rated capacity of 33.47 MMBTUH at 80% boiler efficiency. The boiler was manufactured by Cleaver-Brooks and is a horizontal, multiple pass, dry type, fire tube boiler with a forced draft fan.

A gas-turbine generator is present for a "black" start of the plant and peaking duty. The gas turbine is a simple cycle, single shaft, two bearing, dual fired turbine capable of producing 20,150 kW of electricity.

Two (2) mechanical dust collectors with inlet vanes, tubes, and hoppers are used on Unit 3 to collect particulate matter and unburned carbon resulting from the combustion of #6 fuel oil. The collectors are designed to remove particulate matter from 4.4 million pounds per hour of flue gas exhaust. The collected material is removed from the hoppers and transported to OG&E's Sooner Generating Station where it is incinerated in the boilers.

In 1993, OG&E received permission to burn waste oil and nonhazardous waste ~~(BIF)~~ at this facility. Approval has also been granted to burn up to 3,000 gallons per year of antifreeze in the boilers.

SECTION III. EQUIPMENT

EUG 1 Facility Wide

EU ID#	Point ID#	EU Name/Model	Construction Date
None	None	Facility	1968 - 1970

EUG 2 Boilers

EU ID#	Point ID#	EU Name/Model	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 (gas fuel) 3,681 (oil fuel)	5/28/70

EUG 3 Auxiliary Boiler

EU ID#	Point ID#	EU Name/Model	Heat Capacity (MMBTUH)	Construction Date
3-B	02	Auxiliary Boiler	33.47	1974

EUG 4 Gas Turbine

EU ID#	Point ID#	EU Name/Model	Heat Capacity (MMBTUH)	Construction Date
4-B	01	Gas Turbine	300	5/28/70

EUG 5 Storage Tanks

EU ID#	Point ID#	EU Name/Model	Capacity (Gallons)	Installation Date
5-B	01	#1 Light Fuel Oil Tank	2,310,000	1970
5-B	02	#2 Light Fuel Oil Tank	2,310,000	1972
5-B	03	Heavy Fuel Oil Tank	12,600,000	1975
5-B	04	Heavy Fuel Oil Tank	126,000	1975
5-B	05	Gasoline Tank	1,500	1992

Stack Parameters

Point	Height (ft)	Diameter (ft)	Flow (ACFM)	Temperature (°F)
2-B-01	178	15	472,075	247
2-B-02	178	15	472,075	247
2-B-03	350	18	1,383,374	304

SECTION IV. EMISSIONS

Emission estimates reflect continuous operations (8,760 hr/yr) using emission factors as follow:

- Boilers 1 and 2: gas fuel emissions factors from AP-42 (7/98) for boilers larger than 100 MMBTUH and pre-NSPS: 0.28 lb/MMBTU NO_X, 0.084 lb/MMBTU CO, 0.0055 lb/MMBTU VOC, 0.0076 lb/MMBTU PM_{10}, and 0.0006 lb/MMBTU SO_2. Although the two units are capable of burning liquid fuels, no modeling of SO_2 impacts has been done, so usage of liquid fuels will not be discussed or authorized.
- Boiler 3: gas fuel emissions factors from AP-42 (7/98) for boilers larger than 100 MMBTUH and pre-NSPS: 0.28 lb/MMBTU NO_X, 0.084 lb/MMBTU CO, 0.0055 lb/MMBTU VOC, 0.0076 lb/MMBTU PM_{10}, and 0.0006 lb/MMBTU SO_2; oil fuel emissions from AP-42 (9/98) for boilers larger than 100 MMBTUH burning No. 6 fuel oil: 47 lb/Mgal NO_X, 5 lb/Mgal CO, 0.76 lb/Mgal VOC, 19.88 lb/Mgal PM_{10}, and 260.05 lb/Mgal SO_2 (assuming 1.65% sulfur in fuel oil; the CEM equation in Part 75 gives a slightly different SO_2 emission rate). Residual oil has a heating value of 150,000 BTU/gal. Although the facility may burn distillate fuel instead of residual, residual oil constitutes the worst-case emissions case.
- Tank emissions: EPA's "TANKS4.09."
- Auxiliary boiler: gas fuel emissions factors from AP-42 (7/98) for boilers smaller than 100 MMBTUH: 0.10 lb/MMBTU NO_X, 0.084 lb/MMBTU CO, 0.0055 lb/MMBTU VOC, 0.0076 lb/MMBTU PM_{10}, and 0.0006 lb/MMBTU SO_2. Maximum annual emissions were estimated at 2,900 hours.
- Gas turbine: gas fuel emissions factors from AP-42 (4/00): 0.32 lb/MMBTU NO_X, 0.082 lb/MMBTU CO, 0.0021 lb/MMBTU VOC, 0.0066 lb/MMBTU PM_{10}, and 0.0006 lb/MMBTU SO_2. 500 hours per year operations were used for annual emissions.
- HAP emissions from gas burning: factors in AP-42 (7/00) Section 1.4.

SCENARIO I: GAS FUEL

	PM_{10}		SO_2		NO_X		VOC		CO	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
2-B-01	41.65	182.42	3.29	14.40	1,534.4	6,720.7	30.14	132.01	460.32	2016.20
2-B-02	41.65	182.42	3.29	14.40	1,534.4	6,720.7	30.14	132.01	460.32	2016.20
2-B-03	41.77	182.95	3.30	14.44	1,538.9	6,740.3	30.23	132.40	461.66	2022.09
4-B-01	1.98	0.50	0.18	0.05	96.00	24.00	0.63	0.16	24.60	6.15
3-B-02	0.25	0.37	0.02	0.03	3.35	4.85	0.18	0.27	2.81	4.08
5-B-01	--	--	--	--	--	--	0.12	0.53	--	--
5-B-02	--	--	--	--	--	--	0.12	0.53	--	--
5-B-03	--	--	--	--	--	--	0.01	0.01	--	--
5-B-04	--	--	--	--	--	--	0.01	0.01	--	--
Totals	**127.30**	**548.66**	**10.08**	**43.32**	**4,707.1**	**20,211**	**91.58**	**397.93**	**1,409.7**	**6,064.7**

SCENARIO II: OIL FUEL (BOILER 3)

	PM_{10}		SO_2		NO_X		VOC		CO	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
2-B-01	41.65	182.42	3.29	14.40	1,534.4	6,720.7	30.14	132.01	460.32	2,016.20
2-B-02	41.65	182.42	3.29	14.40	1,534.4	6,720.7	30.14	132.01	460.32	2,016.20
2-B-03	487.94	2,137.18	6,381.64	27,951.6	1,153.38	5,051.80	18.65	81.69	122.70	537.43
4-B-01	1.98	0.50	0.18	0.05	96.00	24.00	0.63	0.16	24.60	6.15
3-B-02	0.25	0.37	0.02	0.03	3.35	4.85	0.18	0.27	2.81	4.08
5-B-01	--	--	--	--	--	--	0.12	0.53	--	--
5-B-02	--	--	--	--	--	--	0.12	0.53	--	--
5-B-03	--	--	--	--	--	--	0.01	0.01	--	--
5-B-04	--	--	--	--	--	--	0.01	0.01	--	--
Totals	**573.47**	**2,502.9**	**6,388.4**	**27,980**	**4,321.5**	**18,522**	**80.00**	**347.22**	**1,070.8**	**4,580.1**

FACILITY WIDE HAP EMISSIONS

	Emissions	
Pollutant	**lb/hr**	**TPY**
Benzene	0.035	0.151
Dichlorobenzene	0.020	0.086
Formaldehyde	1.234	5.405
Hexane	29.621	129.739
Toluene	0.056	0.245

SECTION V. BART ANALYSIS

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.

BART-eligible sources include the following sources:

(1) Sources that have the PTE 250 TPY or more of a visibility-impairing air pollutant;
(2) Sources in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
(3) Sources 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 MMBTUH heat input and fossil-fuel boilers of more than 250 MMBTUH heat input).

Seminole Units 1, 2, and 3 are fossil-fuel fired boilers with heat inputs greater than 250 MMBTUH. 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 TPY 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. 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. Visibility impact modeling previously 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.

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.

This review summarizes the BART determination for Seminole Units 1, 2, and 3. Because the Seminole Generating Station has a total generating capacity in excess of 750 MW, the Appendix Y guidelines were used in preparing the BART determination. Based on an evaluation of potentially feasible retrofit control technologies, including an assessment of the costs and visibility improvements associated therewith, OG&E is proposing the following BART control technologies and emission rates.

Seminole Units 1, 2, and 3 Proposed BART Permit Limits and Control Technologies

Unit	Proposed NO_X Emission Limit	Proposed BART Technology
1	0.203 lb/MMBTU (30-day average)	Combustion Controls (LNB/OFA+FGR)
2	0.212 lb/MMBTU (30-day average)	Combustion Controls (LNB/OFA+FGR)
3	0.164 lb/MMBTU (30-day average)	Combustion Controls (LNB/OFA+FGR)

Seminole Units 1 and 2 became operational in 1968, and Unit 3 became operational in 1970. All three units are Babcock & Wilcox wall-fired boilers, and all three units fire natural gas as their primary fuel. Number 2 fuel oil has been used as a secondary fuel on occasion in Unit 3 for limited durations. Because the units primarily fire natural gas there are no sulfur dioxide (SO_2) or particulate matter (PM) emission control systems. Seminole Unit 3 was designed with flue gas recirculation (FGR) for nitrogen oxide (NO_X) control.

Class I Areas Near the Seminole Station
- Wichita Mountains Wildlife Refuge (WMWR - Oklahoma) 178 km
- Caney Creek Wilderness Area (CCWA - Arkansas) 242 km
- Upper Buffalo Wilderness Area (UBWA - Arkansas) 310 km
- Hercules-Glades Wilderness Area (HGWA - Missouri) 387 km

Visibility impact modeling was conducted by OG&E to determine the baseline predicted maximum 98th percentile Δ-dv visibility impact from the Seminole Generating Station. Although visibility impact modeling at existing actual emissions did not exceed the 0.5 Δ-dv threshold, modeling at the maximum 24-hour pound per hour (lb/hr) emission rate from all three units on a continuous basis (maximum baseline emissions) exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, the facility was determined to be a BART-applicable source subject to the BART determination requirements.

BART Requirements

A determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable. The BART analysis must take into consideration: (1) the technology available; (2) the costs of compliance; (3) the energy and non-air-quality environmental impacts of compliance; (4) any pollution control equipment in use at the source; (5) the remaining useful life of the source; and (6) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Step 1. Identify all available retrofit control technologies.
Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Step 1 of the BART determination requires applicants to identify potentially applicable retrofit control technologies that represent the full range of demonstrated alternatives. Potentially applicable retrofit control alternatives can include pollution prevention strategies, the use of add-on controls, or a combination of control strategies. Control technologies required under the new source review (NSR) program as best available control technology (BACT) or lowest achievable emission rate (LAER) are available for BART purposes and must be included as potential control alternatives. However, EPA does not consider BART as a requirement to redesign the source when considering available control alternatives.

In an effort to identify all potentially applicable retrofit technologies appropriate for use at each station, the following information sources were consulted:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) Database;
- New & Emerging Environmental Technologies (NEET) Database;
- EPA's New Source Review bulletin board;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State new source review permits and BACT determinations for coal-fired power plants;
- Recently submitted Federal and State new source review permit applications submitted for coal-fired generating projects; and
- Technical journals, reports, newsletters and air pollution control seminars.

Step 2. Eliminate Technically Infeasible Options.
In step 2 of the BART determination, the technical feasibility of each potential retrofit technology is evaluated. Control technologies are considered technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. A demonstration of technical infeasibility must be based on physical, chemical, and engineering principles and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility. Options that are technically infeasible for the intended application are eliminated from further review.

Step 3. Evaluate Control Effectiveness of Remaining Control Technologies.
Step 3 of the BART determination involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions under review. Control effectiveness is generally expressed as the rate at which a pollutant is emitted after the control system has been installed. The most effective control option is the system that achieves the lowest emissions level.

Step 4. Evaluate Impacts and Document the Results.
Step 4 of the BART determination involves an evaluation of potential impacts associated with the technically feasible retrofit technologies. The following evaluations should be conducted for each technically feasible technology:

(1) Costs of Compliance;
(2) Energy Impacts; and
(3) Non-Air Quality Environmental Impacts.

Costs of Compliance
The economic analysis performed as part of the BART determination examines the cost effectiveness of each control technology, on a dollar per ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from baseline emissions to calculate tons of pollutant controlled per year. Annual costs are calculated by adding annual operation and maintenance costs to the annualized capital cost of an option. Cost effectiveness ($/ton) of an option is simply the annual cost ($/yr) divided by the annual pollution controlled (ton/yr). In addition to the cost effectiveness relative to the base case, the incremental cost effectiveness to go from one level of control to the next more stringent level of control may also be calculated to evaluate the cost effectiveness of the more stringent control.

Energy Impact Analysis
The energy requirements of a control technology should be examined to determine whether the use of that technology results in any significant or unusual energy penalties or benefits. Two forms of energy impacts associated with a control option can normally be quantified. First, increases in energy consumption resulting from increased heat rate may be shown as total BTU or fuel consumed per year, or as BTU per ton of pollutant controlled. Second, the installation of a particular control option may reduce the output and/or reliability of equipment. This reduction would result in decreased electricity available to the power grid and/or increased fuel consumption due to use of less efficient electrical and steam generation methods.

Non-Air Quality Environmental Impact Analysis
The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, increased water consumption, and land use impacts from waste disposal. Impact analyses conducted in step 4 should take into consideration the remaining useful life of the source. For example, the remaining useful life of the source may affect the cost analysis (specifically, the annualized costs of retrofit controls).

Step 5. Evaluate Visibility Impacts.
Step 5 of the BART determination addresses the degree of improvement in visibility that may reasonably be anticipated to result from the use of a particular control technology. CALPUFF modeling, or other appropriate dispersion modeling, should be used to determine the visibility improvement expected from the potential BART control technology applied to the source. Modeling should be conducted for SO_2, NO_X, and direct PM emissions ($PM_{2.5}$ and/or PM_{10}).

Although visibility improvement must be weighted among the five factors in a BART determination (along with the costs of compliance, energy and non-air-quality environmental impacts, existing pollution control technologies in use at the source, and the remaining life of the source) only potential retrofit control technologies meeting the other four factors were evaluated for visibility impacts. For example, potential retrofit technologies that are not technically feasible will not be evaluated for visibility impacts. The final regulation also states that sources that elect to apply the most stringent controls available need not conduct an air quality modeling analysis for the purpose of determining its visibility impacts.

SEMINOLE UNITS 1, 2, AND 3 BART DETERMINATION

The BART determination process described in Appendix Y of 40 CFR Part 51 (summarized above) was used to identify BART controls for Seminole Units 1, 2, and 3. Because the applicant has proposed to restrict fuel usage for all three boilers to natural gas, SO_2 and PM_{10} emissions are minimal. Also, there are no SO_2 or PM_{10} post-combustion control technologies with a practical application to a natural gas fired boiler. Therefore, the Appendix Y methodology was used to evaluate BART control technologies for NO_X emissions only.

Existing Operating Parameters for Seminole Units 1, 2, and 3

Parameter	Unit 1	Unit 2	Unit 3
Configuration	Wall-Fired Boiler	Wall-Fired Boiler	Wall-Fired Boiler
Gross Output (nominal)	567 MW	567 MW	567 MW
Maximum Input (MMBTUH)	5,480	5,480	5,496
Primary Fuel	Natural Gas	Natural Gas	Natural Gas
Existing NO_X Controls	None	None	FGR
Existing SO_2 Controls	None	None	None
Existing PM_{10} Controls	None	None	None

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.

Baseline Actual Emissions for Seminole Units 1, 2, and 3

	Unit 1		Unit 2		Unit 3	
Pollutant	**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

Presumptive BART Emission Rates

In the final Regional Haze Rule, EPA established presumptive BART emission limits for NO_X for certain electric generating units (EGU) based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls. The presumptive limits apply to EGU 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. Because Seminole Units 1, 2, and 3 are natural gas-fired units, the presumptive BART emission limits are not applicable.

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.

BART DETERMINATION FOR NITROGEN OXIDES (NO_X)

The formation of NO_X is determined by the interaction of chemical and physical processes occurring primarily within the flame zone of the boiler. There are two principal forms of NO_X designated as "thermal" NO_X and "fuel" NO_X. The principal mechanism of NO_X formation in natural gas combustion is thermal NO_X. Thermal NO_X formation is the result of oxidation of atmospheric nitrogen contained in the inlet gas in the high-temperature, post-flame region of the combustion zone. Fuel NO_X is formed by the oxidation of nitrogen in the fuel. Due to the characteristically low fuel nitrogen content of natural gas, NO_X formation through the fuel NO_X mechanism is insignificant.

The major factors influencing thermal NO_X formation are temperature, the concentration of combustion gases (primarily nitrogen and oxygen) in the inlet air, and residence time within the combustion zone. As these three factors increase, NO_X emission levels increase. Advanced burner designs can regulate the distribution and mixing of the fuel and air to reduce flame temperatures and residence times at peak temperatures to reduce NO_X formation.

Step 1: Identify Potentially Feasible NO_X Control Options

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 below.

List of Potential NO_X Control Options

1) Combustion Controls
    i) Low NO_X Burners & Overfire Air (LNB/OFA)
    ii) FGR

2) Post-Combustion Controls
    i) Selective Non-Catalytic Reduction (SNCR)
    ii) Selective Catalytic Reduction (SCR)
3) Innovative Control Technologies
    i) Rotating Overfire Air (ROFA)
    ii) ROFA + SNCR (Rotamix)
    iii) Pahlman Process
    iv) Wet NO_X Scrubbing

Step 2: Technical Feasibility of Potential Control Options

NO_X control technologies can be divided into two general categories: combustion controls and post combustion controls. Combustion controls reduce the amount of NO_X that is generated in the boiler. Post-combustion controls remove NO_X from the boiler exhaust gas. The technical feasibility of each potentially applicable NO_X control technology, with respect to natural-gas fired boilers, is evaluated below.

Combustion Controls

The rate of NO_X formation in the combustion zone is a function of free oxygen, peak flame temperature and residence time. Combustion techniques designed to minimize the formation of NO_X will minimize one or more of these variables. Combustion control options that may be applicable to Seminole boilers are described below.

Low NO_X Burners and Overfire Air (LNB/OFA)

LNB limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NO_X emissions during the combustion process.

In the OFA process, the injection of air into the firing chamber is staged into two zones, in which approximately 5% to 20% of the total combustion air is diverted from the burners and injected through ports located above the top burner level. Staging of the combustion air reduces NO_X formation by two mechanisms. First, staged combustion results in a cooler flame, and second the staged combustion results in less oxygen reacting with fuel molecules. The degree of staging is limited by operational problems since the staged combustion results in incomplete combustion conditions and a longer flame.

LNB/OFA emission control systems have been installed as retrofit control technologies on existing coal, oil, and natural gas-fired boilers. Natural gas-fired boilers the size and age of Seminole Units 1, 2, and 3 retrofit with LNB/OFA combustion technologies would be expected to achieve average emission reductions in the range of 25% to 40% from baseline, depending on the baseline emission rate and boiler operating conditions. Depending on the baseline NO_X concentration and boiler load, controlled emissions would vary between approximately 135 to 250 ppmvd @ 3% O_2 (0.16 to 0.30 lb/MMBTU).

Seminole Units 1, 2, and 3 do not operate as base load units. In general, all three units have historically operated as "peaking units" responding to increased demand for electricity. As peaking units, operating loads and boiler heat inputs vary substantially on a daily and seasonal basis. The daily heat input to each boiler varies significantly, that heat input to the boilers varies seasonally, and that the boilers typically operate at approximately 40% load.

Although LNB/OFA controls are a technically feasible retrofit technology on natural gas-fired boilers, combustion controls on gas-fired boilers may not be as effective under all boiler operating conditions, especially during load changes and at low and high operating loads. Controlling the stoichiometric and temperature profiles of the combustion flame, and maintaining the air/fuel mixing needed for NO_X control, becomes more difficult under these operating scenarios. ~~Baseline NO_X emission rates are lowest at heat inputs in the range of approximately 1,500 to 2,100 MMBTUH.~~ NO_X emissions tend to increase at lower and higher heat inputs. Finally, the mechanisms used to reduce NO_X formation (e.g., cooler flame and reduced O_2 availability) also tend to increase the formation and emission of CO and VOC. Combustion control systems on gas-fired boilers must be designed to minimize NO_X formation while keeping CO and VOC emission rates within acceptable limits.

Comment [A1]: Found on page 12 of BART Determination and appears to be part of the example that has been removed. This sentence and following sentence appear to state similar things. Prefer to strike this statement since it could also be construed as part of the example language that was removed.

Based on information available from burner control vendors and engineering judgment, it is expected that combustion controls, including LNB and OFA, on the wall-fired boilers can be designed to achieve an average control efficiency of 25% from baseline emissions under all normal operating conditions, including low load operation, load changes, and high load operation. Assuming 25% reduction from baseline emission rates, controlled NO_X emissions from Seminole Units 1, 2, and 3 would average:

- Seminole Unit 1: 0.254 lb/MMBTU (~ 210 ppmvd @ 3% O_2)
- Seminole Unit 2: 0.266 lb/MMBTU (~ 220 ppmvd @ 3% O_2)
- Seminole Unit 3: 0.164 lb/MMBTU (~ 135 ppmvd @ 3% O_2)

<u>Flue Gas Recirculation (FGR)</u>
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. In the first type of application, the FGR system takes flue gas from the outlet of the economizer through an FGR fan to supply FGR flow to the furnace or to the windbox. The mixed flue gas/combustion air flow supplied to the windbox should be controlled such that the windbox oxygen content is not lower than approximately 17%. Lower oxygen content would reduce the oxygen available for combustion and could promote the formation of excess CO and VOC emissions. This method of FGR is currently in service on Seminole Unit 3, and would be a technically feasible retrofit option for Units 1 and 2.

The second type of FGR (referred to as Induced FGR) also takes flue gas from the outlet of the economizer but ducts it to the inlet of the existing forced draft (FD) fan. At the inlet of the FD fan, recycled flue gas is mixed with incoming combustion air and introduced into the windbox. With this design, the limitation resides in the construction of the FD fan. Recycled flue gas could increase total flow through the FD fan by about 20%. Therefore, the FD fan typically requires replacement. In addition, as the percentage of flue gas recirculated back through the FD fans increases, so does the overall temperature of the gas in the FD fan. In general, the gas temperature in the FD fan should not be greater than approximately 175°F. Higher temperatures than 175°F would result in higher than normal maintenance on the FD fan and could lead to premature failure of the fan. Both FGR designs are technically feasible retrofit options for gas-fired boilers. Either system would be expected to achieve an additional 15% reduction (compared to LNB/OFA only), or approximately 40% overall reduction from baseline. Because of the requirement to replace the FD fan, the first FGR design option would most likely be the preferred retrofit design for Seminole Units 1 and 2.

Assuming an overall NO_X reduction of 40% from baseline, emissions from Seminole Units 1, 2, and 3 with LNB/OFA and FGR would average:

- Seminole Unit 1: 0.203 lb/MMBTU (~ 165 ppmvd @ 3% O_2)
- Seminole Unit 2: 0.212 lb/MMBTU (~ 175 ppmvd @ 3% O_2)
- Seminole Unit 3: 0.164 lb/MMBTU (~ 135 ppmvd @ 3% O_2)

Post-Combustion Controls

Post-combustion NO_X control systems with potential application to Seminole Units 1, 2, and 3 are discussed below.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at high flue gas temperatures (approximately 1600°F - 1900°F). The NH_3 or urea reacts with NO_X in the flue gas to produce N_2 and water as shown in the equations below.

$$(NH_2)_2CO + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$
$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_X removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,700 °F. At temperatures below the desired operating range, the NO_X reduction reactions diminish and unreacted 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 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, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_X ratio, and fuel sulfur content.

SNCR control systems have been installed as retrofit NO_X control systems on small and medium sized coal- and gas-fired boilers; however, SNCR has not been used on large boilers (i.e., boilers larger than approximately 300 MW). Large boilers, including Seminole Units 1, 2, and 3, would present several design problems making it difficult to ensure that the reagent (urea or NH_3) would be injected at the optimum fuel 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 NH_3 injection points capable of achieving adequate mixing within the required temperature zone. Higher NH_3 injection rates would be needed to achieve adequate mixing. This design would tend to result in relatively high levels of unreacted NH_3 in the flue gas (NH_3 slip). Furthermore, 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 at the requisite temperature.

Installation of an SNCR control system on large boilers, such as those at Seminole, has not been demonstrated in practice. As described above, there are several currently unresolved technical difficulties with applying SNCR to large boilers (including the physical size of the boiler, and adequate reactant/flue gas mixing within the required temperature range). SNCR control would even be more difficult to design for boilers operating as peaking units due to the continuous changes in flue gas flow rates and temperatures. Assuming that SNCR could be installed on Seminole Units 1, 2, and 3, NO_X control effectiveness would be marginal, and, depending on boiler exit temperatures, could actually result in additional NO_X formation.

Because SNCR has not been designed for, or demonstrated on, large boilers, and because there remains several currently unresolved technical difficulties with applying SNCR to a large gas-fired boiler (especially boilers that typically operate as peaking units), it was determined that SNCR is not an available NO_X retrofit control technology for Seminole Units 1, 2, and 3, and SNCR will not be evaluated further in the BART determination.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting NH_3 into boiler flue gas in the presence of a catalyst to reduce NO_X to N2 and water. Anhydrous NH_3 injection systems may be used, or NH_3 may be generated on-site from a urea feedstock. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The performance of an SCR system is influenced by several factors including flue gas temperature, SCR inlet NO_X level, the catalyst surface area, volume and age of the catalyst, and the amount of NH_3 slip that is acceptable.

The optimal temperature range depends on the type of catalyst used, but is typically between 560 °F and 750 °F to maximize NO_X reduction efficiency and minimize ammonium sulfate formation. This temperature range typically occurs between the economizer and air heater in a large utility boiler. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NO_X removal decreases.

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 MMBTUH) 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. Catalyst that has been in service for a period of time will have decreased performance because of normal deactivation and deterioration. Catalyst that is no longer effective due to plugging, blinding or deactivation must be replaced. In addition, flue gas temperature is an important component of SCR effectiveness. SCR control systems on gas-fired units that operate as peaking units would require time to adjust to continuous changes in boiler load, flue gas flow rate, and flue gas temperature.

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. An emission rate of 0.04 lb/MMBTU is equivalent to an average NO_X concentration in the flue gas of approximately 33 ppmvd @ 3% O_2.

Innovative NO_X Control Technologies

A number of innovative NO_X control systems, including multi-pollutant control systems, were identified as potential retrofit control technologies during the review of available documents. Innovative NO_X control technologies with potential application to the BART study include boosted over-fire air (e.g., MobotecUSA's ROFA® system), advanced SNCR control systems (e.g., MobotecUSA's Rotamix® system), Enviroscrub's multi-pollutant Pahlman™ process, and wet NO_X scrubbing systems.

Rotating Opposed Fired Air (ROFA) and Rotomix

ROFA is a boosted OFA 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. The ROFA nozzles are designed to increase turbulence within the furnace. Increased turbulence should prevent the formation of stratified laminar flow, enable the furnace volume to be used more effectively for the combustion process, and reduce the maximum temperatures of the combustion zone.

The ROFA system consists of air injection boxes, duct work and supports, the ROFA fan, and control system instrumentation. A ROFA system was installed on an existing 80-MW (gross) coal-fired utility boiler in the summer of 2002. Test results showed that the ROFA system reduced NO_X emissions from baseline levels 0.6 lb/MMBTU to approximately 0.2 lb/MMBTU at full load. At lower loads (approximately 40 MW), the ROFA system reduced NO_X emissions from 0.6 lb/MMBTU to 0.3 lb/MMBTU. The turbulent air injection and mixing provided by ROFA allows for the effective mixing of chemical reagents with the combustion products in the furnace. MobotecUSA's Rotamix® system combines the ROFA system with urea injection into the flue gas (SNCR) to reduce NO_X emissions. The turbulent mixing created by the ROFA system is designed to improve distribution of the NH_3/urea reagent and may reduce the NH_3/urea injection required by the SNCR control system. A Rotamix control system was installed on the same 80-MW unit in the spring of 2004.

ROFA and Rotamix® systems have been demonstrated on smaller boilers but have not been demonstrated in practice on boilers similar in size to Seminole Units 1, 2, and 3. OFA control systems are a technically feasible retrofit control technology and 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 will not be evaluated as a specific control system, but will be included in the overall evaluation of combustion controls (e.g., LNB/OFA).

The Rotamix system is a SNCR control system coupled with the ROFA rotating injection nozzle design. The technical limitations previously discussed, including the physical size of the boiler, inadequate NH_3/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 determined not to be available for Seminole Units 1, 2, and 3 and will not be evaluated further in the BART determination.

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. Manganese compounds are soluble in water in the +2 valence state but not in the +4 state. This property is used in the Pahlman sorbent capture and regeneration procedure, in that Pahlmanite sorbent is reduced from the insoluble +4 state to the +2 state during the formation of manganese nitrates and sulfates. These species are water-soluble, allowing the sulfate, nitrate and Mn+2 ions to be dissociated and the Mn+2 to be oxidized again to Mn+4 and regenerated. In general, the liquid metal oxide Pahlmanite sorbent is injected as the flue gas enters a spray dryer. The sorbent dries as it passes through the spray dryer and is collected downstream at the fabric filter baghouse. NO_X and SO_2 will react with the sorbent to form manganese sulfates and nitrates as the flue gas passes through the filter cake.

The filter cake is pulsed off-line into a wet regeneration process. The regenerated sorbent is stored in liquid form to be employed again via the spray dryer. The captured nitrogen and sulfur can be purified and may be converted into granular fertilizer by-products. 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 technical 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 considered an available NO_X control system for Seminole Units 1, 2, and 3 and will not be further evaluated in the BART Analysis.

Wet NO_X Scrubbing Systems

Wet scrubbing systems have been used to remove NO_X emissions from fluid catalytic cracking units (FCCU) 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 considered available or technically feasible retrofit control systems for Seminole Units 1, 2, and 3 and will not be further evaluated in this BART Analysis.

Technical Feasibility of Potential NO_X Control Technologies

		In Service On		
Control Technology	**NO_X Control Efficiency**	**Gas-Fired Boilers?**	**Other Sources?**	**Technically Feasible?**
LNB/OFA	25% reduction	Yes~~X~~	Yes	Yes
LNB/OFA+FGR	40% reduction	Yes ~~X~~	Yes	Yes[1]
SNCR	NA	Yes ~~X~~	No	No[2]
SCR	0.04 lb/MMBTU	Yes ~~X~~	Yes	Yes[3]
ROFA	NA	Yes ~~X~~	Yes	Yes[4]
Rotamix (SNCR)	NA	Yes ~~X~~	Yes	~~Yes~~[5]No[5]
Pahlman Process	NA	~~X~~No	No	No[6]
Wet NO_X Scrubbing	NA	~~X~~No	Yes	~~Yes~~[7]No[7]

Comment [A2]: This table is a copy of Table 3-2 on pages 21 & 22 of the BART Determination. Appears to be a cut & paste issue.

1 Seminole Unit 3 is currently equipped with FGR control

2 SNCR has been applied to smaller coal- and gas-fired boilers. Not a technically feasible nor available retrofit technology for Seminole Units 1, 2, and 3. SNCR has been used as a retrofit technology on small and medium sized (<300 MW) boilers, but has not been demonstrated, and would present significant engineering and operational challenges for a large utility boiler. There are several currently unresolved technical difficulties

associated with applying SNCR on a large gas-fired boiler. Furthermore, SNCR may not be effective on boilers that typically operate as peaking units.

3 SCR is a technically feasible retrofit technology for Seminole Units 1, 2, and 3. The effectiveness of the SCR system will depend on site-specific considerations including the NH_3 injection rate, site-specific flue gas characteristics, NH_3 slip, and frequency of catalyst changes.

4 ROFA control systems have been demonstrated on small coal-fired boilers, and would be a technically feasible retrofit control technology. However, there is no technical basis to conclude that ROFA will provide additional NO_X control beyond that achievable with other OFA control systems on Seminole Units 1, 2, and 3. Therefore, ROFA will be evaluated along with other OFA control systems.

5 Rotamix control systems have been demonstrated on small coal-fired boilers. However, there are several currently unresolved technical difficulties associated with applying SNCR-type systems on a large gas-fired boiler. Therefore, Rotamix is not considered an available retrofit control technology for Seminole Units 1, 2 & 3.

6 Bench- and pilot-scale testing has been conducted on coal-fired boilers, however, there is limited data available assessing the technical feasibility of this system on large natural gas-fired boilers. This technology is not considered an available NO_X control technology for Seminole Units 1, 2 & 3.

7 The system has been used on refinery fluid catalytic cracking units and small coal-fired boilers, but has not been used on large natural gas-fired boilers. Wet NO_X scrubbing systems are not available or technically feasible for Seminole Units 1, 2, and 3.

Step 3: Rank the Technically Feasible NO_X Control Options by Effectiveness

Technically Feasible NO_X Control Technologies

	Seminole Unit 1	Seminole Unit 2	Seminole Unit 3
	NO_X Emission Rate	NO_X Emission Rate	NO_X Emission Rate
Control Technology	**(lb/MMBTU)**	**(lb/MMBTU)**	**(lb/MMBTU)**
SCR	0.040	0.040	0.040
LNB/OFA + FGR	0.203	0.212	0.164
LNB/OFA	0.254	0.266	NA[1]
Baseline[2]	0.339	0.354	0.219

1 Seminole Unit 3 is currently equipped with FGR. Consequently, it is assumed that LNB/OFA without FGR is not an available alternative for this unit.

2 Baseline NO_X emissions used in this BART analysis were based on the highest 24-hour block emissions reported by each unit during the baseline period. Baseline NO_X emission rates (lb/MMBTU) were calculated by dividing the maximum hourly mass emission rate (lb/hr) by the full load heat input to each boiler. The relatively high short-term baseline emission rates were used to predict maximum potential visibility impacts, and to provide a conservative estimate of the cost effectiveness of potentially feasible retrofit control technologies. The short-term baseline emission rates should in no way be interpreted as a potential violation of the facility's permitted emission limits, which are averaged over a longer period of time.

Step 4: Evaluate the Technically Feasible NO_X Control Technologies

NO_X Control Technologies – Economic Evaluation
The most effective NO_X retrofit control system, in terms of reduced emissions, that is considered to be technically feasible for Seminole Units 1, 2, and 3 includes combustion controls (LNB/OFA) and post-combustion SCR. This combination of controls should be capable of achieving the lowest controlled NO_X emission rate on an on-going long-term basis. The effectiveness of the SCR system is dependent on several site-specific system variables, including the size of the SCR, catalyst layers, NH_3/NO_X stoichiometric ratio, NH_3 slip, and catalyst deactivation rate. Furthermore, 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. Based on emission rates achieved in practice at similar sources, and including a reasonable margin to account for normal system fluctuations and the fact that the Seminole boilers are operated as peaking units, the combination of combustion controls and SCR should achieve an average controlled NO_X emission rate of 0.04 lb/MMBTU (30-day average). The second most effective NO_X retrofit control system that is considered technically feasible for Seminole Units 1, 2, and 3 includes combustion controls (LNB/OFA+FGR). The combination of LNB/OFA+FGR is expected to achieve an average control efficiency of approximately 40% from baseline on gas-fired units that operate at varying loads and are typically operated as peaking units. The third most effective NO_X retrofit control system considered technically feasible is the combination of LNB/OFA without FGR. This combination of controls is expected to achieve an average control efficiency of approximately 25% from baseline.

Economic impacts associated with the LNB/OFA, FGR, and SCR control systems were evaluated in accordance with EPA guidelines (40 CFR Part 51 Appendix Y). In accordance with guidelines Part III of Appendix Y, 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, projected emission rates (lb/hr) were calculated based on the expected controlled emission rate (lb/MMBTU) achievable on a 30-day rolling average and heat input to the boiler at full load.

Because Seminole Units 1, 2, and 3 have historically operated as peaking units, cost impact evaluations, including total annual costs and total annual emission reductions, were calculated using a more representative annual capacity factor. From 2002 through 2005, annual capacities for each unit were typically in the range of approximately 25% to 30%. Evaluating economic impacts of potential retrofit control technologies using a capacity of 100% would not be representative of actual operations. Using a more representative capacity factor would more accurately reflect actual economic impacts. For this evaluation, annual operating costs and annual emission reductions were calculated assuming an annual capacity factor of 50%.

Seminole Units 1, 2, and 3 Annual Capacity Factor Estimates

Unit	Heat Input 2002-2005	Potential Heat Input at 100% Capacity Factor[1]	Annual Capacity Factor
	(MMBTU)	(MMBTU)	(%)
Unit 1	50,674,995	192,019,200	26.4%
Unit 2	49,114,291	192,019,200	25.6%
Unit 3	47,356,409	192,579,840	24.6%

[1] Potential heat input was calculated based on full load boiler heat inputs of 5,480 mmBtu/hr (Units 1 & 2) and 5,496 mmBtu/hr (Unit 3), and assuming 8,760 hours/year operation at full load.

Formatted: Superscript

Formatted: Superscript

Formatted: Font: 10 pt

Cost estimates were compiled from a number of data sources. 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., NH_3), 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.

Summarized below are the expected controlled NO_X emission rates, and annual NO_X mass emissions (based on 50% capacity factor), associated with each technically feasible retrofit technology. A capacity factor of 50% was used because it represents a conservatively high annual capacity for each unit based on historical capacity factors. The capital costs and annual operating costs associated with building and operating each control system (based on 50% capacity factor) is also included below. Finally, the average annual cost effectiveness and incremental annual cost effectiveness for each NO_X control system. A detailed summary of the cost estimates used in this BART determination was included in application.

Seminole Generating Station - Annual NO_X Emissions

	NO_X Emission Rate (lb/MMBTU)			Maximum Annual NO_X Emissions (TPY)[1]			Annual Reduction (TPY from baseline)		
Control Technology	Unit 1	Unit 2	Unit 3	Unit 1	Unit 2	Unit 3	Unit 1	Unit 2	Unit 3
LNB/OFA+SCR	0.04	0.04	0.04	480	480	481	3,588	3,768	2,155
LNB/OFA+FGR	0.203	0.212	0.164	2,436	2,544	1,974	1,632	1,704	622
LNB/OFA	0.254	0.266	NA	3,048	3,192	NA	1,020	1,056	NA
Baseline	0.339	0.354	0.219	4,068	4,248	2,636	--	--	--

[1] Emissions for the BART analysis are based on maximum heat inputs of 5,480 MMBTUH (Units 1 & 2) and 5,496 MMBTUH (Unit 3). Annual emissions were calculated assuming 4,380 hours/year per boiler (50% capacity factor).

Seminole Generating Station - NO_X Emission Control System Cost Summary (per boiler)[1]

Control Technology	Total Capital Investment[3] ($)	Total Capital Investment ($/kW-net)	Annual Capital Recovery Cost ($/year)	Annual Operating Costs ($/year)	Total Annual Costs ($/year)
LNB/OFA+SCR[2]	$104,230,200	$221.8	$8,943,000	$8,175,600	$17,118,600
LNB/OFA+FGR[2]	$16,977,200	$36.1	$1,456,700	$1,190,900	$2,647,600
LNB/OFA	$9,432,200	$20.1	$809,300	$588,600	$1,397,900

1 Capital costs are similar for each unit, however, there are no FGR retrofit costs associated with Unit 3. A summary of the capital cost estimates for each unit is provided in Attachment A of the analysis.

2 Capital costs for the SCR option include the cost of combustion controls (LNB/OFA) plus SCR. Capital costs for the FGR option include the costs of LNB/OFA plus FGR.

3 Capital costs include the cost of major components and indirect installation costs such as foundations, mechanical erection, electrical, piping, and insulation for the control system.

Seminole Generating Station - NO_X Emission Control System Cost Effectiveness (total)

Control Technology	Total Annual Cost[1] ~~Total Annual Cost[1]~~ ($/year)	Annual Emission Reduction (TPY)	Average Cost Effectiveness ($/Ton)	Incremental Cost Effectiveness[2] ($/Ton)
LNB/OFA+SCR	$51,233,000	9,511	$5,387	$8,078
LNB/OFA+FGR	$6,698,400	3,998	$1,675	$1,984
LNB/OFA	$4,199,000	2,738	$1,534	--

1 Total annual costs 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.

2 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.

Comment [A3]: The cost effectiveness for Seminole's NOx control is not correct and will need to be reevaluated similar to the Sooner/Muskogee SO2 emission control cost effectiveness done earlier. OG&E will provided the updated costs once available.

Formatted: Complex Script Font: Times New Roman, 10 pt, Not Bold, Not Superscript/ Subscript

The average annual cost effectiveness of NO_X controls systems on Seminole Units 1, 2, and 3 range from approximately $1,534/ton for combustion controls (LNB/OFA) to approximately $5,387/ton for combustion controls plus SCR. FGR controls on Seminole Units 1 & 2 reduce NO_X emissions at an average cost effectiveness of approximately $1,675/ton and an incremental cost effectiveness of approximately $1,984/ton (compared to LNB/OFA alone).

Equipment costs, retrofit challenges, and annual operating costs all have a significant impact on the annualized cost of SCR control systems. Significant annual operating costs include the energy cost associated with the additional pressure drop across the SCR and costs associated with replacing the SCR catalyst as it degrades over time. 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 FGR); however, the incremental cost associated with this reduction is approximately $44,534,600 per year, or $8,078/ton.

As part of the BART rulemaking, EPA established presumptive NO_X emission limits applicable to coal-fired EGUs greater than 200 MW at power plants with a generating capacity greater than 750 MW. Although the presumptive levels do not apply to natural gas-fired units, EPA developed the limits based on control strategies considered to be generally cost-effective for such units. For all types of boilers, other than cyclone units, the presumptive limits were based on the use of combustion control technologies. EPA estimated that the "costs of such controls in most cases range from just over $100 to $1,000 per ton" (see, 70 FR 39135).

The average cost effectiveness of combustion controls (LNB/OFA and LNB/OFA+FGR) on Seminole Units 1, 2, and 3 are higher than the cost effectiveness of presumptive BART controls on large EGU boilers. The cost effectiveness of controls needed to achieve the BART presumptive levels on large coal-fired EGU was estimated to be in the range of $100 to $1,000/ton. Combustion controls on Seminole Units 1, 2, and 3 have cost effectiveness values of $1,534 to $1,675/ton for LNB/OFA and FGR controls, respectively. Although the cost effectiveness of combustion controls on Seminole Units 1, 2, and 3 are somewhat higher than EPA's presumptive BART cost effectiveness evaluation, the costs are not so great as to exclude combustion controls as BART.

Both the average and incremental cost effectiveness of SCR on Seminole Units 1, 2, and 3 are significantly worse than the cost effectiveness of NO_X control at other BART-applicable units. The SCR would result in approximately $44,534,600 per year additional costs at the Seminole Generating Station. Therefore, SCR should not be selected as BART based on lack of cost effectiveness. Although SCR does not appear to be cost effective, it will be included in the evaluation of the remaining factors to assure that the BART determination considers all relevant information.

NO_X Control Technologies – Environmental Impacts

Combustion modifications designed to decrease NO_X formation (lower temperature and less oxygen availability) also tend to increase the formation and emission of CO and VOC. Therefore, the combustion controls must be designed to reduce the formation of NO_X while maintaining CO and VOC formation at an acceptable level. Other than the NO_X/CO-VOC trade-off, there are no environmental issues associated with using combustion controls to reduce NO_X emissions.

Operation of an SCR system has certain collateral environmental consequences. In order to maintain low NO_X emissions, some excess NH_3 will pass through the SCR. NH_3 slip will increase with lower NO_X emission limits, and will also tend to increase as the catalyst becomes deactivated. NH_3 slip from an SCR designed to achieve a controlled NO_X emission rate of 0.04 lb/MMBTU (30-day average) on a gas-fired boiler would be in the range of 2-5 ppm during the initial operation of the SCR. As the catalyst ages and becomes either deactivated or blinded, NH_3 slip can increase; however, the NH_3 slip rate is not expected to exceed 7-10 ppm under normal operating conditions.

The storage of NH_3 on-site increases the risks associated with an accidental NH_3 release. Depending on the type, concentration, and quantity of NH_3 used, NH_3 storage/handling will be subject to regulation as a hazardous substance under CERCLA, Section 313 of the Emergency Planning and Community Right-to-Know Act, Section 112(r) of the Clean Air Act, and Section 311(b)(4) of the Clean Water Act. One strategy that can be used to minimize the risk associated with on-site NH_3 handling is to design the ammonia handling system as a urea-to-NH_3 conversion system. Urea ($(NH_2)_2CO$) can be delivered to the station as an aqueous solution or as a dry solid, and urea storage/handling does not create the process safety concerns associated with handling anhydrous NH_3.

Seminole Generating Station Summary of NO_X BART Impact Analysis

Control Technology	Annual Controlled Emissions [1]	Annual Emission Reductions	Average Cost Effectiveness	Incremental Cost Effectiveness	Summary of Environmental Impacts
	(TPY)	(TPY)	($/Ton)	($/Ton)	
LNB/OFA+SCR	1,441	9,511	$5,387	$8,078	NH_3 emissions; & NH_3 storage & handling.
LNB/OFA+FGR	6,954	3,998	$1,675	$1,984	Potential increase in CO/VOC emissions.
LNB/OFA	8,214	2,738	$1,534	--	Potential increase in CO/VOC emissions.
Baseline	10,952	base	--	--	--

[1] Annual controlled emissions (total for 3 units) were calculated based on full load boiler heat inputs of 5,480 MMBTUH (Units 1 & 2) and 5,496 MMBTUH (Unit 3) and assuming 4,380 hours/year operation per boiler (50% capacity factor).

Step 5: Evaluate Visibility Impacts

To evaluate the relative effectiveness of potentially feasible NO_X retrofit control technologies, NO_X emissions were modeled at the projected post-retrofit controlled emission rates. In accordance with EPA guidelines (40 CFR Part 51 Appendix Y Part III), post-retrofit emission rates used in the modeling analysis to determine visibility impairment impacts reflect steady-state operating conditions during periods of high capacity utilization. Post-retrofit emission rates (average lb/hr rate on a 24-hour basis) were calculated using the expected controlled emission rate achievable on a 30-day rolling average multiplied by the boiler heat input (MMBTUH) at full load. The visibility modeling methodology is described further in Section VI. CALPUFF Modeling.

NO_X Visibility Assessment / Visibility Improvement[1]

	WMWR		UBWA		HGWA		CCWA	
Control Technology	**98th % Δ-dv**	**% Improvement**	**98th % Δ-dv**	**% Improvement**	**98th % Δ-dv**	**% Improvement**	**98th % Δ-dv**	**% Improvement**
Baseline	~~1.04~~1.073	--	~~0.39~~0.351	--	0.336	--	~~0.69~~0.588	--
LNB/OFA	0.813	~~22~~24%	0.262	~~33~~25%	0.251	~~24~~25%	~~0.44~~0.438	~~36~~26%
LNB/OFA+FGR	~~0.67~~0.707	~~17~~13%	~~0.25~~0.221	~~4~~16%	0.218	~~16~~13%	~~0.44~~0.370	~~0~~16%
LNB/OFA+SCR	0.154	78%	0.044	~~84~~80%	0.044	~~81~~80%	0.074	~~84~~80%

[1] Δ-dv values included in this table represent the modeled visibility impacts only from NO_X emissions associated with each NO_X retrofit control scenario.

Combustion controls (LNB/OFA) reduce modeled visibility impacts at each Class I Area by approximately ~~26~~25%. Combustion controls plus FGR reduce modeled visibility impacts by an additional ~~4~~ 13 - 16% at each Class I Area. SCR control provides additional improvement in modeled visibility impacts; however, it is important to note that visibility impacts at three of the Class I Areas (Upper Buffalo, Hercules-Glades, and Caney Creek) are below the 0.5 Δ-dv threshold with combustion controls. It is also important to note that visibility impacts were modeled assuming full load heat input 8,760 hours per year. Seminole Units 1, 2, and 3 operate as peaking units and are typically operated at approximately 40% load and achieve capacity factors in the range of 25% to 30%.

Modeled visibility impacts at the Wichita Mountains Class I Area at the 98th percentile level with combustion controls (LNB/OFA+FGR) are 0.707 Δ-dv. SCR controls designed to reduce emissions to 0.04 lb/MMBTU reduce modeled visibility impacts to 0.154 Δ-dv, a 0.564 Δ-dv improvement. As discussed previously, the incremental increase in total annual costs associated with SCR controls is approximately $44,534,600/year. Therefore, the incremental cost effectiveness of the SCR control systems would be in the range of approximately $79.0 MM/dv. The average cost effectiveness of the SCR controls systems (based on modeled impacts at the Wichita Mountains) would be in the range of $55.7 MM/dv (based on modeled visibility impacts of 1.073 Δ-dv (baseline) and 0.154 Δ-dv (LNB/OFA+SCR) and total annual costs of $51,233,000). Both of these costs are significantly higher than the expected cost of BART controls on large EGU, and should preclude SCR from consideration as BART.

NO_X Average Visibility Cost Impact Evaluation[1]

Control Technology	**Total Annual Cost**	**Modeled Visibility Impairment**	**Visibility Impairment Improvement from Baseline**	**Average Improvement Cost Effectiveness**
	($/yr)	**98th % Δ-dv***	**(dv)**	**($/dv/yr)**
Baseline	--	1.073	--	--
LNB/OFA	$4,199,000	0.813	0.260	$16.15 MM/dv
LNB/OFA+FGR	$6,698,400	0.707	0.366	$18.30 MM/dv
LNB/OFA+SCR	$51,233,000	0.154	0.919	$55.75 MM/dv

Comment [A4]: Several of the Δ-dv and % Improvement numbers do not match what was submitted in Table 3-9 on page 30 of the BART Determination. Do not know if this is a typo or if some parameter change occurred and the numbers were recalculated and resubmitted?

Comment [A5]: This was noted as 25% in BART Determination see page 30.

Comment [A6]: The range was noted as 13-16% in BART Determination see page 30.

[1] Δ-dv values included in this table represent the modeled visibility impacts only from NO_X emissions associated with each NO_X retrofit control scenario. Visibility impairment at the nearest Class I Area (Wichita Mountains) was used for the cost effectiveness evaluation.

NO_X Incremental Visibility Cost Impact Evaluation

Control Technology	Total Annual Cost	Incremental Annual Cost	Modeled Visibility Impairment	Incremental Visibility Impairment Improvement	Incremental Improvement Cost Effectiveness
	($/yr)	**($/yr)**	**98th % Δ-dv***	**(dv)**	**($/dv/yr)**
Baseline	--	--	1.073	--	--
LNB/OFA	$4,199,000	--	0.813	--	--
LNB/OFA+FGR	$6,698,400	$2,499,400	0.707	0.106	$23.58 MM/dv
LNB/OFA+SCR	$51,233,000	$44,534,600	0.154	0.553	$80.53 MM/dv

[1] Δ-dv values included in this table represent the modeled visibility impacts only from NO_X emissions associated with each NO_X retrofit control scenario. Visibility impairment at the nearest Class I Area (Wichita Mountains) was used for the cost effectiveness evaluation.

Proposed BART for NO_X Control at Seminole Units 1, 2, and 3

OG&E is proposing combustion controls and FGR (LNB/OFA+FGR) as BART for Seminole Units 1, 2, and 3. This combination of control technologies represents the most effective technically and economically feasible NO_X retrofit technology for the existing boilers. The combination of proposed combustion controls is expected to reduce NO_X emissions by 40% from existing baseline emissions under all normal boiler operating conditions, including load changes, low load operations, and high load operations. A 40% reduction in emissions from baseline for each unit results in the following controlled NO_X emission rates:

- Seminole Unit 1: 0.203 lb/MMBTU
- Seminole Unit 2: 0.212 lb/MMBTU
- Seminole Unit 3: 0.164 lb/MMBTU

Note that Seminole Unit3 is currently designed with FGR; therefore, emissions from Unit 3 under the FGR control option only include LNB/OFA retrofit controls.

Formatted: Font: 8 pt, Complex Script Font: 8 pt

Formatted: No bullets or numbering

The average cost effectiveness of LNB/OFA+FGR control systems is estimated to be in the range of $1,675/ton and $18.3 MM/dv/yr. While these cost effectiveness numbers are somewhat higher than EPA's cost estimate for presumptive BART controls on large coal-fired EGUs, they are not of such magnitude as to exclude combustion controls as BART on the gas-fired units at Seminole. The addition of an SCR control system could provide incremental NO_X reductions; however, costs associated with SCR control are significant, and incremental visibility improvements are limited. The average cost effectiveness of SCR control systems on all three units is estimated to be $5,387/ton and $55.75 MM/dv/yr. These costs are significantly higher than the average cost of NO_X control at similar sources. In the BART rule, EPA concluded that the cost of controls to meet the BART NO_X presumptive level on large coal-fired EGUs "in most cases range from just over $100 to $1,000 per ton" (see, 70 FR 39135). The average cost effectiveness of SCR on Seminole Units 1, 2, and 3 are high because of the relatively low average NO_X emission rates that can be achieved with combustion controls and the fact that Seminole Units 1, 2, and 3 are operated as peaking units (limiting annual mass emissions).

Modeled incremental visibility improvements associated with SCR controls are less than 0.3 Δ-dv at all Class I Areas, except the Wichita Mountains where SCR controls result in a modeled visibility improvement of 0.553 Δ-dv (compared to LNB/OFA+FGR controls). Because of the limited improvement in modeled visibility impacts, the cost effectiveness of SCR control, on a $/dv basis is significant. Furthermore, compared to the costs and modeled visibility impacts associated with LNB/OFA+FGR controls, the incremental cost effectiveness of SCR is estimated to be $8,078/ton and more than $80.5 MM/dv/yr. Both costs are significantly higher than the expected cost of BART controls on large EGUs, and should preclude SCR from consideration as BART.

Proposed BART Permit Limits and Control Technologies

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

SECTION VI. CALPUFF MODELING

Comment [A7]: This section of the memorandum does not reflect the most recent BART determination submitted in May 2008.

Background

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I Areas. The Clean Air Act defines Class I Areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I Area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I Area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

To promote consistency between states in the development of BART modeling protocols and to harmonize the approaches between adjacent RPO, the Central States Regional Air Planning (CENRAP) organization developed BART Modeling Guidelines (December 15, 2005). The intent of the guidelines is to assist CENRAP states and source operators in the development of statewide and source-specific modeling protocols.

The following summarizes the modeling methods and procedures that were followed to conduct a refined CALPUFF modeling analysis for the OG&E Seminole Generating Station. The modeling methods and procedures used to determine appropriate controls for OG&E's BART-eligible sources at the Seminole Generating Station that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I Areas. It was OG&E's intent to determine a combination of emissions controls that would reduce the impact of the Seminole Generating Station to a degree that the 98th percentile of the visibility impact predicted by the modeling due to all of the BART eligible sources at the station was below EPA's recommended visibility contribution threshold of 0.5 Δdv.

<u>Bart-Eligible Sources (Seminole Station)</u>

- Unit 1 - 5,480 MMBTUH Natural Gas Fired Boiler
- Unit 2 - 5,480 MMBTUH Natural Gas Fired Boiler
- Unit 3 - 5,496 MMBTUH Natural Gas Fired Boiler

As required in CENRAP's BART Modeling Guidelines, Class I Areas within 300 km of the Seminole Generating Station were included in the analysis.

<u>CALPUFF Modeling System</u>

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs." CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

The versions of the CALPUFF modeling system programs that were used for conducting OG&E's BART modeling are listed below.

CALPUFF Modeling System Versions

Processor	Version	Level
TERREL	3.311	030709
CTGCOMP	2.22	030528
CTGPROC	2.42	030709
MAKEGEO	2.22	030709
CALMM5	2.4	050413
CALMET	6.211	060414
CALPUFF	6.112	060412
POSTUTIL	1.4	040818
CALPOST	6.131	060410

Modeling Domain

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. The computational domain was set to extend at least 50 km in all directions beyond the Seminole Generating Station and the Class I Areas of interest. The map projection for the modeling domain was Lambert Conformal Conic (LCC) and the datum was the North American Datum 1927 (NAD-27). The reference point for the modeling domain is Latitude 34ºN, Longitude 100.5ºW. The northeast corner was Latitude 37.25ºN and Longitude 92ºW. The meteorological grid spacing was 3 km.

Vertical Layers

Layer	Cell Face Height (m)
1	20
2	40
3	80
4	160
5	320
6	640
7	1,200
8	2,000
9	3,000
10	4,000

The height of the top vertical layer was set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain was divided into 10 layers. The vertical dimensions were weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

Geophysical Data

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

Terrain Data

Terrain data was obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data was then processed by the TERREL program to generate grid-cell elevation averages across the modeling domain.

Land Use Data

USGS Composite Theme Grid (CTG) format Land Use and Land Cover (LULC) data files at 1:250,000 resolution were used. Where 1:250,000 land use data was not available, USGS data at 1:100,000 resolution was used. The USGS CTG format LULC data files were compressed prior to use in the CTGPROC utility processor using the CTGCOMP program. The LULC data were processed by the CTGPROC program to generate land use for each grid cell across the modeling domain.

Compiling Terrain And Land Use Data

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program were then uploaded into the MAKEGEO program to create a geophysical data file that was used as the input for CALMET.

CALMET

CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET was used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, precipitation data, and mesoscale model output to develop the meteorological fields. Upper air observations were not used in generating the meteorological fields.

MM5 Data

Hourly mesoscale data was used as the initial guess field in developing the CALMET meteorological data. The following 5th generation mesoscale model meteorological data sets (or MM5 data) was used in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR
- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data used were subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. The southern set of the extracted MM5 data was used.

The 2001 southern subset of the extracted MM5 data included 30 files that were broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which were broken into 30 to 31 day increment files (1 file per month). The 2001 to 2003 MM5 data extracted by Alpine Geophysics were not able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM5 data in the EPA approved CALMET program, each of the MM5 files had to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data occurred.

The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary, since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it was necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data was not used directly. Instead the data files were modified by adding eight additional hours of data to the end of each file from the beginning of the subsequent file. CALMET was then run using the appended MM5 data to generate a contiguous set of CALMET output files.

Surface Data
Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations was processed for use in CALMET using the SMERGE program.

Missing surface data was filled using procedures recommended by EPA. Missing data periods of 5 hours or less were replaced using these procedures. For periods greater than 5 hours, data was left either unfilled or was not used in CALMET processing. A large enough quantity of surface stations were included in the domain so that overlapping areas of influence would allow data from an alternate station to be used.

The use of multiple stations for meteorological observations in CALMET/CALPUFF provides a substantial enhancement over the steady-state treatment of observations from a single meteorological station. Surface data were extracted from the surface stations. Raw observations from these stations were obtained from the National Climatic Data Center (NCDC). The data was quality assured and then merged using the SMERGE pre-processor to create a single assimilated data file of surface observations for each year analyzed.

Precipitation Data
The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it was necessary to include observations of precipitation in the CALMET analysis. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using the PMERGE program.

Upper Air Data
Upper Air observations were not used in the CALMET analysis (i.e. NOOBS=1).

CALMET Control Parameters
The modeling was conducted using the CENRAP recommended parameters, except the ones listed below. A explanation is also provided as to why the CENRAP recommended parameters were not used for these variables. Most of the differences are due to the inclusion of observation data into the modeling analysis.

CALMET Input Variables Where CENRAP Suggested Value was not Used

Variable	Suggested	Used	Description	Reason
DGRIDKM	6.0	3.0	Grid spacing (km)	Refined grid spacing
NN2	1	2	Last time step for debug data to be printed	Generated debug data for 2 time steps
NZPRN2	0	1	# Of levels at surface to print	Default
NOOBS	2	1	No obs mode	Used surface OBS

CALMET Input Variables Where CENRAP Suggested Value was not Used

Variable	Suggested	Used	Description	Reason
NSSTA	0	47	# Met stations in surf.dat	# of stations
NPSTA	0	135	# Met stations in precip.dat	# of stations
IFORMC	2	1	Format cloud data	N/A - no cloud data used
IKINE	0	1	Adjust winds using kinematic effects	Computed kinematic effects
RMAX1	30	100	Max radius of influence over land in surface layer (km)	IWAQM Phase 2 Study
RMAX2	30	500	Max radius of influence over land aloft (km)	IWAQM Phase 2 Study
RMAX3	30	36	Max radius of influence over water (km)	Used MM5 data spacing
R1	1	50	Weighting of 1st guess surface field (km)	IWAQM Phase 2 Study
R2	1	100	Weighting of 1st guess aloft field (km)	IWAQM Phase 2 Study
ITPROG	2	1	3D temp from observations or MM5	Used surface observations

CALPUFF

The CALPUFF model uses the output file from CALMET together with source, receptor, and chemical reaction information to predict hourly concentration impacts.

Source Emissions

Baseline (pre-BART) emission data was based on CEMS data collected by OG&E over the 2001-03 time frame. In accordance with CENRAP guidelines, the emission rate over the highest calendar day (24-hr average) was used to establish baseline emissions. The units at the Seminole Generating Station operate primarily on natural gas and occasionally fuel oil. During the 2001-03 time frame, only Seminole Unit 3 consumed fuel oil. In addition, these units are operated as peaking units, resulting in an operating profile that varies substantially on a daily and a seasonal basis.

Based on CEM data over the 2001-03 time period, modeled emissions are based on the highest hourly emission rate (based on a 24-hour calendar day average) that occurred from 2001 to 2003. In order to accurately reflect the operating profile (i.e., peaking nature) of these units in the CALPUFF model, a variable emission rate data file was utilized (PTEMARB.dat). This emission data file was developed by utilizing the highest 24-hour emission rate for each calendar month over the 2001-03 time frame.

BASELINE 24-HOUR AVERAGE EMISSION RATES

		SO_2	H_2SO_4	NO_X	PM_{10}
EGU	**Month**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**
Unit 1	January	1.99	0.026	941	0.25
	February	1.69	0.025	718	0.21
	March	2.28	0.035	1048	0.29
	April	2.10	0.032	915	0.27
	May	1.95	0.025	936	0.25
	June	2.06	0.032	942	0.27
	July	2.12	0.032	751	0.27
	August	1.98	0.027.	862	0.25
	September	2.15	0.030	860	0.27
	October	1.68	0.026	595	0.22
	November	2.03	0.025	1072	0.26
	December	2.08	0.028	883	0.27
Unit 2	January	1.89	0.012	954	0.25
	February	1.82	0.021	1,103	0.23
	March	1.94	0.024	1,240	0.25
	April	2.21	0.034	1,209	0.29
	May	2.34	0.031	1,196	0.30
	June	2.15	0.033	1,125	0.28
	July	2.33	0.028	1,322	0.30
	August	2.15	0.033	1,285	0.28
	September	2.44	0.028	1,525	0.31
	October	1.98	0.025	1,026	0.26
	November	1.82	0.000	874	0.23
	December	1.83	0.000	982	0.23
Unit 3	January	2.15	0.025	1,184	0.27
	February	1,142.29	25.148	890	0.22
	March	1,145.01	25.207	857	0.21
	April	1.56	0.024	747	0.20
	May	2.25	0.028	1,055	0.29
	June	204.62	4.505	656	0.23
	July	2.20	0.027	1,136	0.28
	August	2.00	0.030	837	0.26
	September	2.44	0.031	1,226	0.32
	October	2.07	0.026	916	0.26
	November	2.55	0.019	808	0.22
	December	2.06	0.032	878	0.26

Emission estimates for various control scenarios were developed by Sargent and Lundy. Since the units at the Seminole Station are natural-gas fired, NO_X control technologies were primarily evaluated in this analysis. OG&E elected to evaluate cost effectiveness on a facility-wide basis (as opposed to a unit-by-unit basis) and will install the final selected control technology on each of the affected units at the facility.

Point Source Stack Parameters

Unit	UTM E (m)	UTM N (m)	Velocity (ft/s)	Height (ft)	Diameter (ft)	Temp (°F)
Unit 1	707,651	3,871,616	13.58	54.27	4.57	393
Unit 2	707,650	3,871,678	13.58	54.27	4.57	393
Unit 3	707,649	3,871,740	19.85	106.71	5.49	412

The base elevation of each of the units is 290 meters (950 feet) above MSL based on visual inspection of USGS topographic maps. Based on FLM guidance, PM_{10} emissions from natural gas combustion consists of primarily (75%) fine particulate matter (PM_F, considered $PM_{<2.5}$) and (25%) coarse particulate matter (PM_C, considered $PM_{2.5-10}$).

<u>Receptor Locations</u>
The National Park Service (NPS) provides electronic files that include the discrete locations and elevations of receptors to be evaluated in Class I Area analyses. The receptor files for were downloaded from the NPS website, converted into the LCC NAD27 projection, and incorporated into the CALPUFF model.

<u>Background Ozone</u>
Background ozone concentrations were required in order to model the photochemical conversion of SO_2 and NO_X to sulfates (SO_4) and nitrates (NO_3). CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. CENRAP recommended either developing background ozone concentrations from ambient monitors located within the domain being modeled or from the most recent CENRAP CMAQ/CAMx simulation for the 2002 base year. Modeling was conducted using a conservative background concentration of 40 ppb. This is the default background concentration from the CENRAP protocol.

<u>Background Ammonia</u>
Background concentrations of ammonia were required to model the formation of ammonia nitrates and sulfates. CENRAP recommended developing background concentrations from the most recent CENRAP CMAQ or CAMx simulation for the 2002 base year. Since the CMAQ/CAMx modeled and observed monthly averaged concentrations exhibit wide spatial variability and the data is not readily available, a conservative background concentration of 3 ppb was used. This is the default background concentration from the CENRAP protocol.

CALPUFF Model Control Parameters

Puff splitting is a generally accepted option in refined modeling analyses over large model domains for assessing impacts on Class I Areas. However, this option would have required significant computer resources and longer runtime. Based on previous model runs performed on domains (and restricted computational grids) of the size described in this report, it is expected that runtimes could increase by a factor for 4 to 5 with the inclusion of puff-splitting. Due to this, OG&E evaluated the use of this option during the modeling analysis and provide details in the modeling report about its use.

The modeling was conducted using the CENRAP recommended parameters, except the ones listed below. A explanation is also provided as to why the CENRAP recommended parameters were not used for these variables.

CALPUFF Input Variables Where CENRAP Suggested Value was not Used

Variable	Suggested	Used	Description	Reason
NSE	8	6	# Chemical Species to be emitted	SOA and EC not included
MSPLIT	0	1	Puff splitting	Allowed for puff splitting due to distances
DGRIDKM	6.0	3.0	Grid Spacing (km)	Refined Grid Spacing
NH_3	8.0E-5	NA	Scavenging Coefficient for liquid precipitation (s^{-1})	
	0	NA	Scavenging Coefficient for frozen precipitation (s^{-1})	
MH2O2	1	0	Background H2O2 Concentrations	Need to chose 0 to use monthly background value
BCKH2O2	1	12*1	Background Monthly H2O2 Concentrations	
OFRAC	0.2	0.15, 0.15, 0.2, 0.2, 0.2, 0.2, 0.2, 0.2, 0.2, 0.2, 0.2, 0.15	Organic Fraction for SOA option	Irrelevant MCHEM ≠ 4
IPTU	1	3	Units for Point Source emissions	Used lb/hr

CALPOST

A three-year CALPOST analysis was conducted to determine the visibility change in deciview (dv) caused by OG&E's BART-eligible sources when compared to a natural background.

Light Extinction Algorithm

EPA's currently approved algorithm for reconstructing light extinction (as opposed to the new equation for reconstructing light extinction recommended by the IMPROVE Steering Committee) was used. The background extinction coefficient b_{ext}, background is affected by various chemical species and the Rayleigh scattering phenomenon. The light extinction equation is provided below.

$$b_{ext} = 3*f(RH)*[(NH_4)_2SO_4] + 3*f(RH)*[NH_4NO_3] + 4*[OC] + 1*[PM_F] + 0.6*[PM_C] + 10*[EC] + b_{Ray}$$

The algorithm was used to calculate the daily light extinction attributable to the Seminole Station's BART eligible sources and light extinction attributable to a natural background. The change in deciviews based on the source and background light extinctions was evaluated using the equation below.

$$\Delta\ dv = 10 * \ln[(b_{ext,\ background} + b_{ext,\ source})/b_{ext,\ background}]$$

CALPOST Processing Method

CALPOST Method 6, which calculates hourly light extinction impacts for the source and background using monthly average relative humidity adjustment factors was used in the refined BART analysis. Monthly Class I Area-specific relative humidity adjustment factors based on the centroid of the Class I Areas as included in Table A-3 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program* were used.

Monthly Humidity Factors

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek	3.4	3.1	2.9	3.0	3.6	3.6	3.4	3.4	3.6	3.5	3.4	3.5
Hercules-Glades	3.2	2.9	2.7	2.7	3.3	3.3	3.3	3.3	3.4	3.1	3.1	3.3
Upper Buffalo	3.3	3.0	2.7	2.8	3.4	3.4	3.4	3.4	3.6	3.3	3.2	3.3
Wichita Mountains	2.7	2.6	2.4	2.4	3.0	2.7	2.3	2.5	2.9	2.6	2.7	2.8

Natural Background

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 used.

Default Average Annual Natural Background Levels

Class I Area	Region	SO_4	NO_3	OC	EC	Soil	Coarse Mass
Caney Creek	WEST	0.12	0.10	0.47	0.02	0.50	3.00
Hercules-Glades	EAST	0.23	0.10	1.40	0.02	0.50	3.00
Upper Buffalo	EAST	0.23	0.10	1.40	0.02	0.50	3.00
Wichita Mountains	WEST	0.12	0.10	0.47	0.02	0.50	3.00

Evaluating Visibility Results

~~Trinity compared~~A comparison of ~~the~~ high ~~of the~~ 2001 through 2003 daily Δ dv values output by CALPOST to a contribution threshold of 0.5 Δ dv. Since the 98th percentile Δ dv values (the 7th highest value, 22nd highest over three years) output by CALPOST was greater than 0.5 Δ dv, the source was subject to BART regulations and submitted their BART determination to AQD.

Summary of CALPOST Control Parameters

A listing of the CALPOST parameters ~~that Trinity~~ used in OG&E's modeling analysis is referenced in the table below. In cases where a parameter to be used is different than what CENRAP recommended, a short explanation as to the difference is provided.

CALPUFF Input Variables Where CENRAP Suggested Value was not Used

Variable	Suggested	Used	Description	Reason
BEXTBTBK	12	NA	Background Extinction for MVISBK=1	Not necessary since MVISBK=6
RHFRAC	10	NA	% of Particles affected by RH	Not necessary since MVISBK=6

SECTION VII. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application and listed in OAC 252:100-8, Appendix I, are listed below. Recordkeeping for activities indicated with "*" is listed in the Specific Conditions.

* Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power or for peaking power service not exceeding 500 hours/year. There is one rarely-used 20,150kW emergency generator.

* Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period. One 1,500-gallon gasoline tank is located on-site and records are kept which demonstrate the facility uses much less than the 2,175 gallons/day.

* Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature. There is one 550 gallon vehicle diesel storage tank on site.

Cold degreasing operations utilizing solvents that are denser than air. Cold degreasing occurs in the maintenance shop.

Hazardous waste and hazardous materials drum staging areas. The facility stores used oil and used solvent in the machine shop and in the basement between Units 1 and 2. Used antifreeze is stored in the garage building.

Sanitary sewage collection and treatment facilities other than incinerators and Publicly Owned Treatment Works (POTW). Stacks or vents for sanitary sewer plumbing traps are also included (i.e., lift station). The facility operates a sanitary sewage collection and treatment facility.

Surface coating and degreasing operations which do not exceed a combined total usage of more than 60 gallons/month of coatings, thinners, clean-up solvents, and degreasing solvents at any one emissions unit. The facility conducts surface coating and degreasing operations in the maintenance shop. Maintenance is a listed "trivial activity," therefore, no recordkeeping will be required.

Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas. The facility maintains exhaust systems for the environmental laboratory.

Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas. The facility performs small amounts of hand wiping and spraying of solvents.

* Activities that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant. This covers the auxiliary boiler and fuel oil storage tanks; records of throughput and calculated emissions will be required.

SECTION VIII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the operating permit application, or developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies limits for fuel-burning equipment particulate emissions based on heat input capacity. Emissions limitations and anticipated emissions are shown in the following table. Emissions listed for the boilers are based on the allowable emissions. All units are in compliance with this subchapter.

			SC 19 Limit	Calculated Emissions, lb/hr	
EU	**Description**	**MMBTUH**	**lb/hr**	**Scenario I**	**Scenario II**
2B-01	Unit 1 boiler	5,480	656.77	41.65	41.65
2B-02	Unit 2 boiler	5,480	656.77	41.65	41.65
2B-03	Unit 3 boiler	5,496 gas 3,681 oil	658.11 gas 497.31 oil	41.77	487.94
3B-01	Gas turbine	300	80.24	1.98	1.98
3B-02	Aux boiler	33.47	15.11	0.25	0.25

AP-42 (7/1998), Section 1.4 lists the total PM emissions for natural gas to be 0.0076 lb/MMBTU.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas, there is very little possibility of exceeding the opacity standards. When burning fuel oil, the permit will require either using a continuous opacity monitor (COMS) or Method 22 and then Method 9 if visible emissions are detected. The permit will also include reduced visible emission observation requirements when burning fuel oil if no visible emissions are detected or if visible emissions observations using Method 9 are below the 20 % opacity limitation.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 3 establishes short-term ambient standards for SO_2. Air dispersion modeling of Unit 3 was conducted burning 24,521 gal/hr of No. 6 fuel oil with a sulfur content of 1.65% by weight. Results of the modeling are tabulated following. All ambient SO_2 impacts are in compliance with the limitations of Subchapter 31.

SO_2 Ambient Impacts

Averaging Time	SC 31 Limits, μg/m^3	Maximum Impacts, μg/m^3
1-hour	1,200	792
3-hours	650	318
24-hours	130	100
Annual	80	4

Part 5 limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). All of the fuel-burning equipment at this facility was constructed prior to the applicability date.

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]
This subchapter limits NO_X emissions from new fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH. All of the emission units that exceed the 50 MMBTUH threshold are considered existing emission units.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 24, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The facility includes a 1,500-gallon gasoline tank installed in 1992, which is subject to the submerged fill requirement. The fuel oil storage tanks, emergency generator fuel tank, and diesel vehicle fuel tank are not subject since they do not store a VOC with a vapor pressure greater than 1.5 psia.
Part 3 requires loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. This facility does not load tanks with a capacity greater than 200 gallons. Therefore, this requirement is not applicable.
Part 5 limits the VOC content of coatings used in coating lines or operations of parts and products. Any painting operation will involve maintenance coatings of buildings and equipment and emit less than 100 pounds per day of VOC and so is exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained,

and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-7	Minor Facility Permits	not in source category
OAC 252:100-11	Alternative Reduction Plans	not eligible
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-35	Carbon Monoxide	not in source category
OAC 252:100-39	Nonattainment Areas	not in a subject area
OAC 252:100-47	Landfills	not type of emission unit

SECTION IX. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Not Applicable]
Emissions of several regulated pollutants exceed 100 TPY, the level at which PSD defines the facility to be a major source. Any future expansion must be evaluated in the context of PSD significance levels (100 TPY CO, 40 TPY NO_x, 40 TPY SO_2, 40 TPY VOC, 25 TPY PM, 15 TPY PM_{10}, or 0.6 TPY lead). The permit will require the facility to apply for and obtain a PSD 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.

NSPS, 40 CFR Part 60 [Not Applicable]
Subpart D, Fossil-Fuel-Fired Steam Generators. This subpart is applicable to steam generating units constructed after August 17, 1971, which have a capacity greater than 250 MMBTUH heat input. Boilers No. 1, 2, and 3 commenced construction prior to August 17, 1971. The definition of steam generating unit is limited to furnaces or boilers.
Subpart Da, Electric Utility Steam Generating Units. This subpart is applicable to steam generating units constructed, reconstructed, or modified after September 18, 1978, which have a capacity greater than 250 MMBTUH heat input. Boilers No. 1, 2, and 3 and Turbine No. 1 have not been modified or reconstructed after September 18, 1978 and are not subject to this subpart.
Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units which were constructed, reconstructed, or modified after June 19, 1984, but on or before June 19, 1986, and which have a heat input capacity of 100 MMBTUH or more. All of the steam generating units were constructed prior to June 19, 1984 and have not been reconstructed or modified.

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units constructed after June 9, 1989, and with capacity between 10 and 100 MMBTUH. The 33.47 MMBTUH steam generating unit was constructed prior to June 9, 1989, and is not subject to this subpart.
Subpart K, Petroleum Liquid Storage Vessels. This subpart affects petroleum liquid storage vessels with a capacity greater than 40,000 gallons and that commence construction or modification after June 11, 1973, and prior to May 19, 1978. The fuel oil tanks were installed prior to June 11, 1973.
Subpart Kb, VOL Storage Vessels. This subpart affects VOL storage vessels with a capacity greater than or equal to 19,813-gallons that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. The gasoline tank is below the 19,813-gallon threshold for this subpart.
Subpart GG, Stationary Gas Turbines. This subpart affects combustion turbines which commenced construction, reconstruction, or modification after October 3, 1977, and which have a heat input rating of 10 MMBTUH or more. The combustion turbine was constructed prior to the effective date of Subpart GG.
Subpart KKKK, Stationary Gas Turbines. This subpart affects stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005. The combustion turbine was constructed prior to the effective date of this subpart.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, mercury, coke oven emissions, radionuclides or vinyl chloride.

NESHAP, 40 CFR Part 63 [Subpart DDDDD Is Applicable]
Subpart Q, Industrial Cooling Towers. This subpart applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources as defined in § 63.401. This facility does not have or use industrial process cooling towers that are operated with chromium-based water treatment chemicals.
Subpart YYYY, Stationary Combustion Turbines. This subpart affects any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions. The turbine located at this facility is considered an existing turbine since it commenced construction before January 14, 2003. Per § 63.6090(b)(4), existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part.
Subpart DDDDD, Industrial Boilers and Process Heaters. Subpart DDDDD regulated HAP emissions from industrial boilers and process heaters. In March, 2007, the EPA filed a motion to vacate and remand this rule back to the agency. The rule was vacated by court order, subject to appeal, on June 8, 2007. No appeals were made and the rule was vacated on July 30, 2007. Existing and new small gaseous fuel boilers and process heaters (< 10 MMBTUH heat rating) were not subject to any standards, recordkeeping, or notifications under Subpart DDDDD.

EPA is planning on issuing guidance (or a rule) on what actions applicants and permitting authorities should take regarding MACT determinations under either Section112(g) or Section 112(j) for sources that were affected sources under Subpart DDDDD and other vacated MACT. It is expected that the guidance (or rule) will establish a new timeline for submission of section 112(j) applications for vacated MACT standards. Until such time as more guidance is received, AQD has determined that a 112(j) determination is not needed for sources potentially subject to a vacated MACT, including Subpart DDDDD. This permit may be reopened to address Section 112(j) when necessary.

CAM, 40 CFR Part 64 [Not Applicable]
Compliance Assurance Monitoring (CAM) applies to any pollutant specific EU at a major source, that is required to obtain a Part 70 operating permit, if it meets all of the following criteria:

1. It is subject to an emission limit or standard for an applicable regulated air pollutant;
2. It uses a control device to achieve compliance with the applicable emission limit or standard; and
3. It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source thresholds.

The requirements of this part do not apply to any of the following emission limitations or standards:

1. Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act; and
2. Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act.
3. Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in § 64.1.

In addition, the boilers do not use control devices to achieve compliance with an applicable emission limit.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility does not store any regulated substance above the applicable threshold limits. More information on this federal program is available at the web site: http://www.epa.gov/ceppo/.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
Acid Rain Permit No. 2004-186-ARR was issued on November 4, 2004, and remains in effect.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
SO_2 initial allowances as published in 40 CFR 73.10 are listed in Acid Rain Permit No. 96-285-AR. However, allowances can be traded, bought, and sold. Therefore, the actual allowances held by an affected unit may change which will not necessitate a revision to the permit.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
Certification testing has been completed for the CEM system required for each unit, and the EPA has issued approval of certification on September 22, 1997, for all three boilers.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The standard conditions of the permit address the requirements specified at § 82.156 for persons opening appliances for maintenance, service, repair, or disposal; § 82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; § 82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; § 82.166 for recordkeeping; § 82.158 for leak repair requirements; and § 82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

SECTION X. COMPLIANCE

Tier Classification and Public Review

This application has been determined to be Tier II based on the request for a significant modification of a Part 70 operating permit. The applicant has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the real property.

The applicant published the “Notice of Filing a Tier II Application” in the *Newspaper*, a daily newspaper, in Seminole County, on DATE. The notice stated that the application was available for public review LOCATION. The applicant will publish the "Notice of Tier II Draft Permit" in the *Newspaper*, a daily newspaper, in Seminole County. This facility is not located within 50 miles of the Oklahoma border. The draft permit will also be available for pubic review on the Air Quality section of the DEQ Web Page: *http://www.deq.state.ok.us/*.

Information on all permit actions is available for review in the Air Quality section of the DEQ Web page: *http://www.deq.state.ok.us/*.

Inspection

A full compliance evaluation inspection was conducted on March 9, 2005. Mr. Jason Lipscomb of Air Quality who was accompanied by Ms. Melody Martin, Staff Chemist, conducted the inspection. The facility was physically as described in the permit application and supplemental materials. No violations were noted during the inspection.

Fees Paid

Significant modification of a Part 70 source operating permit application fee of $1,000.

SECTION XI. SUMMARY

The facility was constructed and is operating as described in the permit application. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility. Issuance of the modified operating permit is recommended, contingent on EPA and public review.

PERMIT TO OPERATE
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Oklahoma Gas & Electric Company
Seminole Generating Station **Permit No. 2003-400-TVR (M-1)**

The permittee is authorized to operate in conformity with the specifications submitted to Air Quality on December 19, 2003, July 22, 2005, and March 30, 2007, and all supplemental information. The Evaluation Memorandum dated October 27, 2009, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emissions limitations for each point: [OAC 252:100-8-6(a)]

All units in **EUG 2, EUG 3** and **EUG 4** are “grandfathered” (pre-October 1972 construction) or are an “insignificant activity.” There are no hourly or annual emission limits applied to the following units under Part 70, but they are limited to the equipment as is.

Point	Manufacturer	MMBTUH	kW	Serial Number
2-B-01	Babcock & Wilcox El-Paso	5,480	509,719	BW-22731
2-B-02	Babcock & Wilcox El-Paso	5,480	504,604	BW-22826
2-B-03	Babcock & Wilcox El-Paso	5,496	505,980	BW-23416
4-B-01	General Electric	300	20,150	179530
3-B-02	Cleaver-Brooks	33.47	N/A	L-58163

a. The permittee shall either monitor the opacity of discharges using a continuous opacity monitor or conduct daily visual observations. If a daily visual observation is the method of choice, then an EPA Reference Method 22 shall be conducted while burning No. 2 or No. 6 fuel oil for more than 24 continuous hours and records kept of these observations. If visible emissions are detected, then the permittee shall conduct a thirty-minute opacity reading in accordance with EPA Reference Method No. 9.
   i. If a Method 9 observation exceeds 20% opacity the permittee shall conduct at least two additional Method 9 observations within the next 24-hours.
   ii. If more than one six-minute Method 9 observation exceeds 20% opacity in any consecutive 60 minutes; or more than three six-minute Method 9 observations in any consecutive 24 hours exceeds 20% opacity; or if any six-minute Method 9 observation exceeds 60% opacity; the owner or operator shall comply with the provisions for excess emissions in OAC 252:100-9. [OAC 252:100-25]

b. The permittee shall be authorized to utilize natural gas as the primary fuel. Fuel oil (#2 or #6) may be utilized as a secondary fuel in Unit 2-B-03. A permit modification shall be required to burn fuel oil in Units 1 and 2 dependent on a demonstration of compliance with OAC 252:100-31. [OAC 252:100-31]

c. Boilers ~~S~~2-B-01, 2-B-02, and 2-B-03 are authorized to combust non-hazardous waste on an as-needed basis, generated on-site, from other OG&E facilities, or from OG&E employees and retired employees. The waste combusted may include, but is not limited to, used oil, EH fluid and used antifreeze. [OAC 252:100-31]

d. Fuel oil may be burned in only Unit 3. Residual fuel oil shall contain no more than 1.65% by weight sulfur and distillate fuel oil shall contain no more than 1.84% by weight sulfur. [OAC 252:100-31]

EUG 5 (Storage Tanks): VOC emissions from storage tanks are insignificant based on existing equipment items and do not have a specific limitation.

EU ID#	Point ID#	EU Name/Model	Capacity (Gallons)	InstallationDate
5-B	01	#1 Light Fuel Oil Tank	2,310,000	1970
5-B	02	#2 Light Fuel Oil Tank	2,310,000	1972
5-B	03	Heavy Fuel Oil Tank	12,600,000	1975
5-B	04	Heavy Fuel Oil Tank	126,000	1975
5-B	05	Gasoline Tank	1,500	1992

a. Gasoline Tank 5-B-05 shall be operated with a submerged fill pipe.[OAC 252:100-37]

2. The permittee shall be authorized to operate the facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

3. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following: [40 CFR Part 72, 73, and 75]

a. SO_2 allowances.
b. Report quarterly emissions to EPA.
c. Conduct RATA tests.
d. QA/QC plan for maintenance of the CEMS.

4. The following records shall be maintained on-site. All such records shall be made available to regulatory personnel upon request. These records shall be maintained for a period of at least five years after the time they are made. [OAC 252:100-8-6 (a)(3)(B)]

a. Quantity of each type of fuel and other materials burned (monthly).
b. Emissions data as required by the Acid Rain Program.
c. RATA test results from periodic CEMS quality assurance tests.
d. Operating hours for each boiler.

e. Date and time of visual emission observations (Method 22 of 40 CFR Part 60) when burning fuel oil, stack or emission point observed, operational status of the emission unit, observed results and conclusions, and any required Reference Method No. 9 results; or continuous opacity monitor results if used instead of visual monitoring.
f. Sulfur content of fuels per 40 CFR Part 75.

5. No later than 30 days after each anniversary date of the issuance of the original permit (June 21, 1999), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit.
[OAC 252:100-8-6 (c)(5)(a)&(d)]

6. The following records shall be maintained on-site to verify insignificant activities.
[OAC 252:8-6(a)(3)(b)]

a. Fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period: capacity of the tanks and the amount of throughput (annual).
b. Fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: capacity of the tanks and contents.
c. Activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions from that activity (annual).

7. The permittee shall have the discretion of determining which records will be maintained in digital format.

8. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility.
[OAC 252:100-8-6(d)(2)]

a. OAC 252:100-11 Alternative Emissions Reduction
b. OAC 252:100-15 Mobile Sources
c. OAC 252:100-17 Incinerators
d. OAC 252:100-23 Cotton Gins
e. OAC 252:100-24 Grain elevators
f. OAC 252:100-33 NO_X
g. OAC 252:100-35 Carbon Monoxide
h. OAC 252:100-39 Organic Materials
i. OAC 252:100-47 Landfills

9. This permit supersedes all previous Air Quality permits for this facility, except Acid Rain Permit No. 2004-186-ARR, which are now null and void.

10. Boiler 3-B-02 (the auxiliary boiler) is subject to NESHAP, Subpart DDDDD with a compliance date of September 13, 2007. As of that date, the permittee shall comply with all applicable provisions. [40 CFR Part 63, Subpart DDDDD]

11. 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~~ equipment listed in Specific Condition 11.d. no later than five years after USEPA approval of the SIP incorporating the BART requirements or final resolution to any BART related legal action whichever is later.

c. The permittee shall apply for and obtain a construction permit prior to modification of the boilers~~. I~~ if the modifications result in an increase in any air pollutant or results in the emissions of any air pollutant not previously emitted. If the modification will ~~result in~~cause 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, and
   iii. Flue Gas Recirculation.
   Note that Seminole Unit3 is currently designed with FGR.

Formatted: Indent: Before: 0.75", First line: 0.25"

e. The permittee shall maintain the combustion controls (Low-NO_X 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 the maximum production rate at which the affected facilities will be operated, 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
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 ~~achieving~~ the maximum production rate at which the affected facilities will be operated, 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 NO_X, CO, and VOC testing on the boilers at 60% and 100% of the maximum capacity. NO_X 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.
Method 4:	Determination of Moisture in Stack Gases.
Method 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
Method 6C:	Quality Assurance Procedures (Range and Sensitivity, Measurement System Performance Specification, and Measurement System Performance Test Procedures) shall be used in conducting Method 10.
Method 20:	Determination of Nitrogen Oxides and Oxygen Emissions from Stationary Gas Turbines.
Method 25/25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.

Comment [A8]: If the BART emission limit is for NOx are we required to test for CO and VOC?

Comment [A9]: Method 10 references method 7e unsure why 6C is required instead?

Oklahoma Gas & Electric
Attn: David Branecky
Environmental Administrator
P. O. Box 321
Oklahoma City, OK 73101

Re: Permit Application No. **2003-400-TVR (M-1)**
Seminole Generating Station
Seminole County, Oklahoma

Dear Mr. Branecky:

Air Quality has received the permit application for the referenced facility and completed initial review. This application has been determined to be a Tier II application. In accordance with 27A O.S. 2-14-301 and 302 and OAC 252:4-7-13(c) the application and enclosed draft permit are now ready for public review. The requirements for public review of the draft permit include the following steps, which you must accomplish:

1. Publish at least one legal notice for the draft permit (one day) in at least one newspaper of general circulation within the county where the facility is located. (Instructions enclosed)
2. Provide for public review (for a period of 30 days following the date of the newspaper announcement) a copy of the draft permit at a convenient location (preferentially at a public location) within the county of the facility.
3. Send AQD a written affidavit of publication for the notice from Item #1 above together with any additional comments or requested changes, which you may have for the permit application within 20 days of publication.

The permit review time is hereby tolled pending the receipt of the affidavit of publication. Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact the permit writer at eric.milligan@deq.ok.gov or at (405) 702-4217.

Sincerely,

Phillip Fielder, P.E.
Permits and Engineering Group Manager
AIR QUALITY DIVISION

Enclosures

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON STREET, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2003-400-TVR (M-1)

Oklahoma Gas & Electric

having complied with the requirements of the law, is hereby granted permission to operate the Seminole Generating Station, Section 25, T6N, R5E, Seminole County, Oklahoma, subject to the Standard Conditions dated July 21, 2009, and Specific Conditions, both of which are attached.

This permit shall expire May 9, 2011, except as Authorized under Section VIII of the Standard Conditions.

Division Director, Air Quality Division | **Date**

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants

("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.

[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.
[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.
[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.
[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.
[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;

(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of

adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be

certified by an approved technician certification program pursuant to § 82.161;

(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;

(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and

(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.

(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).

(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 C.F.R. § 70.8(d).

(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

OG&E

December 16, 2009

VIA HAND DELIVERY AND E-MAIL

RECEIVED
DEC 16 2009
AIR QUALITY

Ms. Cheryl E. Bradley
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, Oklahoma 73101-1677

Re: Submission of Confidential Documents

Dear Ms. Bradley:

Oklahoma Gas and Electric Company ("OG&E") is providing comments on the Regional Haze State Implementation Plan proposed by the State of Oklahoma, Department of Environmental Quality on November 13, 2009. In connection with Exhibit 3 to OG&E's comments, OG&E is providing ODEQ with the following confidential documents: (i) Howden Variax, Inc., Proposal for Axial Booster Draft Fans, No. N21110, dated December 2, 2009; and (ii) Babcock & Wilcox Power Generation Group, Inc., Price Estimate for Spray Dry Absorber and Pulse Jet Fabric Filter Systems, dated December 12, 2009. Copies of these documents are attached hereto and are marked "Confidential."

The documents listed above contain Confidential Business Information, including pricing information from equipment vendors, and OG&E respectfully requests that they be treated as confidential and exempt from public disclosure under OAC 252:4-1-5(d).

If you have any questions or require any additional information, please feel free to contact me.

Very truly yours,

Ford Benham

Attachments

CHI-1734826v1

This page inserted by Oklahoma Department of Environmental Quality.

Comments

of

Oklahoma Gas and Electric Company

on

Regional Haze Implementation Plan Revision

The comments submitted by OG&E on December 16, 2009, include 81 pages that OG&E has identified as confidential information. These pages include (i) Howden Variax, Inc., Proposal for Axial Booster Draft Fans, No. N21110, dated December 2, 2009; and (ii) Babcock & Wilcox Power Generation Group, Inc, Price Estimate for Spray Dry Absorber and Pulse Jet Fabric Filter Systems, dated December 12, 2009. The pages have been removed as provided by 27A O.S. § 2-5-105(17).

Bud

Oklahoma Chapter of the Sierra Club Comments Regarding Oklahoma Draft Regional Haze State Implementation Plan December 13, 2004

RECEIVED
DEC 1 6 2009
AIR QUALITY

On October 5, 2009, the State of Oklahoma submitted its Draft State Implementation Plan (SIP) Revision for the Regional Haze Program, pursuant to 40 C.F.R. Part 51 et seq. As the local representative for the oldest and largest public interest environmental organization in the United States, the Oklahoma Chapter of the Sierra Club has reviewed the Oklahoma Draft SIP and offers the following comments regarding the adequacies of the SIP.

The leadership of the Oklahoma Chapter of the Sierra Club would like to recognize the diligent efforts put forth by the Oklahoma Department of Environmental Quality (ODEQ) in drafting its Regional Haze SIP. Addressing air quality issues is a critical component to preservation of our nation's natural resources, public health, and citizen opportunities to enjoy our national parks, forests, and wildlife areas. Identifying the causes and nature of factors that influence air quality and visibility is an extremely complex and resource-intensive process; however, the ODEQ utilized its resources effectively in identifying both the causes and potential solutions to these issues in its SIP. The Sierra Club appreciates the opportunity to comment on the revised SIP and looks forward to working with the ODEQ on identifying and implementing solutions to the aforementioned problems.

Collectively, the draft SIP effectively identifies the major causal factors for regional haze within the Class 1 area in Oklahoma, namely the Wichita Mountains Wildlife Refuge. The presentation of data regarding the Wichita Mountains is in depth; however, the draft SIP would be more effective in combating regional haze if it more thoroughly considered the impact of emissions from Oklahoma on Class 1 areas neighboring Oklahoma, namely Caney Creek and Upper Buffalo Wilderness Areas. As demonstrated in tables VI-10 & VI-11, the impacts of required Best Available Retrofit Technology (BART) sources in Oklahoma are not limited to the Wichita Mountains Wildlife Refuge, but have a significant impact upon Caney Creek and Upper Buffalo Wilderness Areas. Therefore, the SIP and its BART analyses would present a more accurate impact upon regional haze if such an in-depth analyses were extended to the aforementioned areas in Arkansas.

Likewise, an important component to the revised SIP is ODEQ's consistent recognition of influential factors from jurisdictions outside of the State of Oklahoma. ODEQ cites in each discussion of particulates and chemical compounds impacting the Class 1 area within Oklahoma the overwhelming impact from point source emissions, area emissions, road and non-road vehicles, and burning that occur primarily in Texas and other jurisdictions. Unlike the thorough explanation provided for Oklahoma based BART sources, non-BART sources, and solutions included in the impending Oklahoma Smoke

Management Program, the draft SIP offers little to no explanation of its efforts to address interstate impacts upon air quality and visibility in the Wichita Mountains.

The programs outlined in the draft SIP for addressing BART and BART exempt point source emissions have been thought through carefully, especially considering the constraints upon ODEQ's monitoring and enforcement capabilities. Acknowledging the impact of particulate transport from Texas, the SIP should offer an explanation of its efforts to address its impact on Oklahoma's Class 1 areas, beyond the impact of the Clean Air Interstate Rule Reductions.

In its sections addressing the impact of BART implementation through 2018 and its conclusive section on attaining maximum visibility standards, the ODEQ stipulates that all steps taken towards implementing BART controls within Oklahoma will have a limited impact upon visibility and regional haze, although compliant with the reasonable progress goals. Considering that between 8,000 and 11,000 Megawatts of new electric generation, largely from coal-fired sources, are either under construction or in the permitting process at the Texas Commission on Environmental Quality, the most significant potential impact Oklahoma can have upon regional haze is through addressing such development and its subsequent effect upon Oklahoma's Class 1 area. Therefore, it is imperative that Oklahoma's SIP include substantive discussions on addressing its role in regional impact mitigation both within and without the State of Oklahoma.

Regarding application of BART emission standards for qualifying facilities in Oklahoma, the Sierra Club applauds ODEQ's analysis provided in its SIP and included Appendices. While the Sierra Club ultimately supports the implementation of BART and Best Available Control Technologies (BACT) for the enhancement of air quality and prevention of significant deterioration, more analysis should be spent on approvable alternatives for BART-eligible sources to comply with Part 70 air quality permits and SIP provisions. Specifically, more analysis is necessary regarding potential fuel-switching from coal-fired steam facilities to natural gas powered facilities, and other portfolio diversification initiatives, such as adoption of renewable energy generation.

As one of the largest contributors to regional haze and air quality degradation, electric generating facilities should be encouraged to utilize the vast wind, solar, and natural gas resources available in Oklahoma. Available controls for natural gas electric generating facilities are substantially more cost effective and generally capture larger amounts of harmful emissions. Additionally, the extrinsic costs of waste disposal for both dry and wet scrubber captured materials via water treatment or landfill disposal make implementation of such technologies for coal-fired electric facilities less attractive to both the consumers and the citizens of Oklahoma. Therefore, if fuel-switching proposals are offered by BART-eligible sources with detailed timelines that could achieve the objectives of the regional haze SIP, they should be considered in lieu of mandatory BART implementation at the existing coal-fired steam facilities. However, until such proposals are offered with guaranteed timelines, the Sierra Club supports the implementation of BART.

Again, the Sierra Club appreciates the efforts put into developing the regional haze SIP by the ODEQ and applauds their analysis. We look forward to working with all stakeholders involved in the process to develop the most effective rules for preserving air quality and visibility in our nation's protected spaces. Thank you for the opportunity to comment on the Regional Haze SIP.

Sincerely,

Robert "Bud" Scott, Esq.
Government Affairs Director
Oklahoma Chapter
Sierra Club

Public Service Company of Oklahoma
1601 Northwest Expressway, Suite 1400
Oklahoma City, OK 73118
www.aep.com

RECEIVED
DEC 16 2009
AIR QUALITY

AEP
PUBLIC SERVICE COMPANY OF OKLAHOMA®

December 16, 2009

Ms. Cheryl Bradley
Oklahoma Department of Environmental Quality
Air Quality Division,
P.O. Box 1677
Oklahoma City, Oklahoma 73101-1677

Reference: American Electric Power/Public Service Company of Oklahoma (AEP/PSO) comments to the Oklahoma Department of Environmental Quality (ODEQ) proposed Draft Regional Haze Rule (RHR) State Implementation Plan (SIP) dated November 13, 2009

Dear Ms. Bradley:

AEP/PSO is pleased to offer the comments below in response to the ODEQ's November 13, 2009 Draft RHR SIP. Please allow us to note that the draft SIP is very well organized and easy to comprehend. It aided our efforts in making an expedient review.

AEP/PSO operates gas- and coal-fired Electric Generating Units (EGU) in Oklahoma. These EGUs will be subject to the Best Available Retrofit Technology (BART) provisions of the RHR addressed in the proposed ODEQ SIP.

At the very outset, AEP/PSO would note that depending on the final disposition of certain requirements in the ODEQ proposed RHR SIP, we would be adversely affected financially and the operating viability of our EGUs could be put in jeopardy. More importantly, in these dire economic times, customers in the state could face untenable cost increases, unless the proposed SIP is modified as suggested herein, and ODEQ takes full advantage of the opportunities for flexibility in its implementation.

AEP/PSO submitted a five-factor analysis at ODEQ's request, which demonstrated that installation of dry FGD to achieve a presumptive BART limit of 0.15 lbs/mmBtu SO_2 at Northeastern Units 3 and 4 is not cost-effective, based on the range of values set forth in the RHR. We further evaluated the basis of our annual average SO2 rate that was used in the five-factor analysis and determined that a realistic depiction of our historical SO2 emission rate is 0.55 lbs/mmBtu. This is based on an EPA, July 5, 2005 guidance document that stated: "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from s baseline period." The cost effectiveness based upon the 0.55 lbs/mmBtu is $6,077 / Ton which further clarifies that the dry FGD is not cost effective.

AEP/PSO is committed to returning to the 0.55 lbs/mmBtu coal as expeditiously as practical at a reasonable cost. The reduced sulfur coal will make significant contributions to visibility improvement in the target Class I areas. Within this same time period, additional reductions will be made at other facilities, and additional information will become available concerning EPA's review of ambient air quality standards and development of replacement rules for the Clean Air Interstate Rule and the Clean Air Mercury Rule. All of these developments should be considered in determining if and how further reductions in SO_2 emissions could be accomplished at Northeastern Units 3 and 4. Therefore, as a contribution to ODEQ's continuing development of plans to implement the reasonable progress goals, AEP/PSO would commit to complete an evaluation of measures that would allow Northeastern Units 3 and 4 to achieve further reductions in SO_2 emissions, up to the presumptive BART limit of 0.15 lbs/mmBtu, and present the results of that evaluation to ODEQ within five years of submittal or seven years after approval of the SIP, whichever is later. The evaluation will include FGD controls if no other alternative measures have been identified that would achieve equivalent reductions. Cost-effective measures that provide needed reductions for target Class I areas and that are identified during ODEQ's review of AEP/PSO's submittal would be implemented on a phased basis after the evaluation is completed based on ODEQ's recommendations.

Recognizing that the RHR implementation is a state driven program, the ODEQ has the authority to determine what is best for its sources, in line with the standards of reasonableness and the other factors required to be considered in the RHR. AEP/PSO addresses these issues below. Our comments are broken down along the lines of general and Draft SIP-content specific considerations.

Background

The proposed SIP is intended to develop air emissions reduction plans to help mitigate aesthetic impacts at Federal Class 1 areas in accordance with the provisions in the Federal RHR. The RHR is premised on a "goal" towards restoration of Federal Class 1 areas to their natural background visibility conditions over a 60-year glide path.

The RHR can be broadly broken down into two regulatory tracks - the BART component and the Reasonable Further Progress goal (RFP). Each has its obligatory requirements as distilled below:

BART Component

- BART applies to a subset of eligible EGUs (those that were in operation and "existed" in a window between 1962 to 1977) in a given state and is based on an EGU specific assessment

- These EGUs, on a one time basis, have to reduce emissions that impair visibility in Class I areas through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[the BART-eligible EGU]….**taking into consideration….the costs of compliance"** along with four other statutory factors
- BART assessment is a site specific determination and is not based solely on the level of visibility improvement achieved after its one time application
- The State has the prerogative and latitude to determine what is construed to be the "best system" for this one time BART determination, following "the statutory five factor analysis"
- The critical factor in the BART assessment, the cost of compliance, is represented in terms of a "cost effectiveness" metric, benchmarked against cost effectiveness factors in the RHR
- BART compliance is generally required to be no later than five (5) years after the United States Environmental Protection Administration's (USEPA) approval of the RHR SIP

RFP Component

- The RFP goal of the RHR is a Class 1 area specific visibility-based assessment over a 60-year timeline (not an EGU specific one time BART assessment)
- It is keyed towards attaining incremental progress towards the ultimate goal of reaching background visibility levels in 60 years, at a given Class 1 area (within or outside of a State)
- The RFP goal is to be monitored in ten year increments over the 60-year timeline (six, ten-year periods) with adjustments made to the visibility milestone goals as appropriate, at the end of each assessment period
- Central to meeting the RFP goals at any Class 1 area are the cumulative emission reductions over time, from different sources, source types, States and even international emissions and the associated improvements in visibility
- EGU BART emission reductions deemed "cost effective" in a given state, are evaluated for their contribution to improved visibility as part of the overall RPG process, for different Class 1 areas
- Thus, a BART eligible unit's obligations towards the RFP goal at any Class 1 is incidental to the RFP process, with the control approach and attendant reductions dictated by a onetime assessment keyed to the statutory five-factor analysis
- States have the authority to establish what is "reasonable" by way of any EGU's reduction obligation towards meeting RFP milestones and seek changes to the RPG requirements, if outcomes are beyond its control
- The RHR give a state with a Class I area the flexibility to tailor the RFP goal for that area. These include: extension to the glide path beyond the 60-year point based on the state's demonstration, applying the reasonable progress factors (including cost of compliance and the time necessary for compliance) to show that

the 60-year period is not reasonable and that the longer period selected by the state is reasonable

General comments to utilize in the SIP offering to the USEPA

Against the above backdrop of pertinent and applicable RHR provisions and AEP/PSO's review of the ODEQ' Draft SIP, we offer these comments and suggestions for consideration and inclusion in the State's SIP submittal to the USEPA:

- The "cost effectiveness" consideration, which is paramount to the BART adjudication is missing from this Draft RHR SIP – AEP/PSO requests that the state review the information presented from the five-factor analyses in light the continued economic recession and the need for greater certainty associated with EGU-specific rulemakings underway at EPA
- ODEQ should make its own determination as to cost-effectiveness based on all of these factors
- The cost-effectiveness numbers developed by EPA for the RHR are the appropriate benchmark for evaluating BART obligations
- As a point of reference, the RHR cites the EPA RACT/BACT/LAER Clearinghouse for Dry FGD for SO_2 control ranging from $393/Ton to $2132/Ton, with an average cost effectiveness of $792/Ton
- AEP/PSO's original cost effectiveness number of $3266lbs/mmBtu and the $6077/Ton as revised based upon a historical 0.55 lbs/mmBtu SO2 emission rate both exceed the high end of EPA's range, allowing for consideration of more cost-effective alternatives
- Even if the RHR USEPA "average cost" was escalated to $1174/Ton (2008 dollars at 5% escalation), the AEP/PSO site specific number for Northeastern 3 and 4 is not cost-effective
- Given that Dry FGD as BART is not "cost effective" for the NE 3 & 4, the uncertainties with evolving regulatory programs and the ODEQ's goal to issue a RHR SIP, AEP/PSO is willing to offer up an alternative SO_2 reduction approach (with demonstrable visibility improvements at the four Class 1 areas of interest to the ODEQ), on an expedited basis for inclusion in the SIP offering to the USEPA
- AEP/PSO offers to return to, and maintain the lower S fuel with potential SO_2 control efficiency of 43% and visibility improvements approximating to 41%, from the baseline modeling conditions at each of the four class 1 areas
- It is being offered as part of a package of steps to make continuing visibility improvements at a reasonable cost for Oklahoma utility customers
- As for the RPG obligations in the SIP, recognizing that a Class 1 area is impacted by a broad suite of sources within and outside of the state and is accomplished over a 60-year glide path, it would be imprudent and contrary to the BART

determination to penalize an EGU within the state to meet aggressive reduction requirements by disregarding cost effectiveness criteria

- The RHR is intended to be a state driven program and the state should take into consideration the current acute economic climate and customer impacts, in placing requirements on its EGU sources to satisfy BART in response to the SIP
- AEP/PSO also offers to complete an evaluation of measures that would allow Northeastern Units 3 and 4 to achieve further reductions in SO_2 emissions, up to the presumptive BART limit of 0.15 lbs/mmBtu, and present the results of that evaluation to ODEQ within five years of submittal or seven years after approval of the SIP, whichever is later. The evaluation will include FGD controls if no other alternative measures have been identified that would achieve equivalent reductions. Cost-effective measures that provide needed reductions for target Class I areas and that are identified during ODEQ's review of AEP/PSO's submittal would be implemented on a phased basis after the evaluation is completed based on ODEQ's recommendations.

<u>Draft SIP Content Specific Comments</u>

These comments are provided to speak to specific items in the Draft SIP (outside of the comments enunciated above in the General Comments section) with a view to:

- reinforce and offer our concurrence on certain Draft SIP limitations identified by the ODEQ that can have implementation consequences for EGU sources
- share our understanding of the intent of specific RHR requirements and contrast those with what is espoused in the Draft SIP
- correct some misstatements about AEP/PSO's BART offerings cataloged in the Draft SIP

<u>Section II A, Monitoring Strategy</u>

❖ The Draft SIP language suggests that the continued operation of IMROVE monitors (that track important visibility performance information and maintained by other entities) at the Wichita Mountains Class 1 area (and presumably other Class 1 areas) will be subject to availability of funding. Additionally, there is a statement that reads <u>"DEQ cannot assess the achievement of reasonable progress at Wichita Mountain without continuation of this monitoring."</u>

❖ AEP/PSO shares the ODEQ's concerns in these matters, especially when EGUs and other sources are expected to commit billions of dollars to protect visibility and help restore Class 1areas to their natural background visibility conditions over a 60-year timeline

- It seems counter to the RPG process and illogical that emission controls will be required without a feedback mechanism to understand the efficacy of the reduction needed and benefits to be derived from near term and future costly actions taken. AEP/PSO joins the ODEQ in expressing our apprehension over the uncertainty and lack of an accountability mechanism for costly investments made (by EGUs and other sources) and benefits derived

Section II B, Monitoring Operation

- This section addresses deficiencies in the IMPROVE monitoring protocol, especially the lack of Ammonium measurement with "its significant contribution to visibility impairment"

- AEP/PSO shares the ODEQ's concerns in this matter. The "complementary role" that the Cation Ammonium plays in visibility impairing Ammonium Sulfate and Ammonium Nitrate particulate formation and the needed reduction of its precursor Ammonia (even if an air shed is Sulfate or Nitrate limited) cannot be neglected

- Recognizing that it takes an Anion and a Cation to form a compound (particulate), the EPA should be asked to address the lack of proper guidance to a balanced approach to visibility reduction and redress the deficiency, before requiring additional and burdensome SO2 and NOx control

Section II C, Calculating Light Extinction From Particulate Concentrations

- AEP/PSO applauds the ODEQ's use of the latest science based New IMPROVE equation in its planning process, in estimating daily light extinctions. AEP/PSO was at the front end of pushing for the revisions to the legacy IMPROVE equation (advocated by the USEPA and the FLMs) that was based on outdated science

- AEP/PSO agrees with the ODEQ's assessment that to make the New IMPROVE equation more robust for future use, EPA should be required to fund and augment the monitors at Wichita Mountains (and other Class 1 areas) to include the measurement of light-absorbing Nitrogen dioxide (NO2) gas, so that this component can be factored into the light extinction calculations. The Electric Power Research Institute (EPRI) has underscored NO2 measurements as a needed enhancement for use in the IMPROVE equation

Section II D, Deciview Haze Index

- ❖ The ODEQ addresses the algorithm used in the Haze Index calculation and the role of the relative humidity component. The ODEQ has correctly identified the need for factoring in hourly relative humidity variations as compared to monthly average numbers currently used and recommended by the EPA and the FLMs.

- ❖ AEP/PSO concurs that an hourly type number would better represent scattering variances and help screen out bad data (high numbers) due to other influences such as fog/rain. It would be important to select impairment days, using the Haze index that could be truly attributable to pollutant impacts

- ❖ EPRI has identified the importance of hourly considerations and has ongoing efforts to better characterize and inform the process. Future assessments to gauge RPG assessments should include the needed refinements to the algorithm

<u>Section II E, Monitoring Data and Light Extinction Calculations</u>

- ❖ This section catalogs various visibility-impacting particulate species for years 2000 through 2007. The common theme from the information presented is that transport from far reaches account for impacts at the Wichita Mountains (and presumably other Class 1 areas)

- ❖ AEP/PSO would encourage the ODEQ to avoid <u>aggressive and immediate EGU SO2</u> <u>and NOx</u> <u>reductions to satisfy RPG</u> recognizing that several regulatory programs are in the pipeline and until there is further clarity on a holistic (and not a piecemeal) approach to regulatory actions

<u>Section III, Natural Conditions,</u>

- ❖ This section offers an excellent treatise on components that affect the all important natural condition estimation. The current estimate of natural conditions is indicated to be based on the use of default Trijonis method. EPRI has identified shortcomings with the Trijonis methodology which is indicated to result in erroneous depiction of true natural conditions and thereby calling for more emissions reductions to satisfy the uniform rate of progress

- ❖ AEP/PSO shares the ODEQ's concerns about "the extremely general character of the (Trijonis) estimate and their inherent assumptions" that "may only apply to broad regional averages, not necessarily specific points" and "include large error, usually a factor of two without any quantified confidence"

- AEP/PSO joins the ODEQ in strongly echoing the need to address the uncertainties identified and in questioning the merits to using the default Trijonis estimate. From an affected sources perspective, this could be punitive in terms of control obligations to meeting unfettered RPG obligations

Section VI Best Available Retrofit Technology,

- In Section VI A., BART-eligible Sources in Oklahoma, the ODEQ indicates that "because of the limiting role of NOx and SO_2 on $PM_{2.5}$ and the uncertainties in assessing the effect of ammonia reductions on visibility, Oklahoma does not consider ammonia among visibility-impairing pollutants"

- AEP/PSO respectfully disagrees with the ODEQ in this matter. The role of Ammonia in Ammonium Sulfate and Ammonium Nitrate particulate formation cannot be discounted in the near term or into the future. A strategy focused singly on aggressive SO2 and NOx control in the near future, without considering Ammonia reduction, would impede attainment of visibility goals

- The emissions inventory provided in Section IV bears testimony to our argument - the Tons of Ammonia in the state inventory for 2002 exceeds the Total SO_2 Tons. Assuming that aggressive controls on SO_2 and NOx are contemplated at the state level, uncontrolled Ammonia in the air shed would still linger to react with transported SO_2 and NOx leading to continued visibility causing particulate formation

- Two considerations emerge from the above discussions: 1).The importance of the role of Ammonia and planning for its controls and 2). Recognition that aggressive ("non-cost effective") state level SO_2 and NOx control as BART to possibly address RFP goal would be ill advised and unjustified until other regulatory programs that address transport issues (currently being considered) are fully resolved

- In Table VI-1, Facilities with BART-eligible Units in Oklahoma, the accurate number of such units at the Northeastern Power Station are 3 (instead of 2 as listed)

- In Section VI B., Determination of Sources Required to Install BART, a statement is made to effect that the ODEQ "will require any BART-eligible source determined to cause or contribute to visibility impairment at the Wichita Mountains or any other Class 1 area to install BART"

- ❖ AEP/PSO would submit that the ODEQ has the discretion and flexibility to determine what is best for its BART-eligible sources, in line with the reasonableness and statutory-factor considerations allowed in the RHR.

- ❖ AEP/PSO concurs with ODEQ's interpretation of the option afforded it in the RHR to exercise its discretion to set a maximum "contribution threshold below 0.5 deciview" and to exempt BART-eligible sources from having to install controls through a dispersion modeling demonstration

- ❖ AEP/PSO supports ODEQ's decision to exempt AEP/PSO's Riverside Power Station based on its (low) source level contribution below the defined threshold, using modeled demonstration

- ❖ Table VI-4, in Section VI B correctly identifies the AEP/PSO BART-eligible sources that will be subject to BART based on "cause or contribute" modeling analysis and the pollutants evaluated

- ❖ AEP/PSO would note that there is a double listing for the Northeastern Power Station Unit 2 in Table VI-4. It is a gas-fired unit and its listing (as part of the coal units) in row 6 under the Facility Name should be deleted

- ❖ AEP/PSO agrees with ODEQ's assertion that "the negligible SO2 and PM emissions from natural gas-fired steam electric plants do not significantly contribute to visibility impairment and therefore not further evaluated". This assertion is supported by the RHR which limits BART considerations for gas-fired units to NOx

- ❖ In Section VI C. Determination of BART Requirements for Subject Sources, AEP/PSO agrees with the ODEQ interpretation that "BART is an emission limit for each pollutant based on the degree of reduction achievable through the application of the best system of continuous emission reduction"

- ❖ AEP/PSO notes that the ODEQ has correctly identified the statutory factors to be considered in deciding on the optimum approach to meet an emission limit. This affords the source the needed flexibility to use the best system of reduction, without restricting to use of control equipment

- ❖ Table VI-5 catalogs such limits for several AEP/PSO units

- ❖ AEP/PSO agrees with the BART NOx emission factors expressed in lb/mmBtu reflected in Table VI-5 for AEP/PSO Gas-fired EGUs at Southwestern Power Station 3, Northeastern Power Station 2 and Comanche Power Station 1 & 2

- AEP/PSO would add that these limits reflect the performance capability, based on use of site specific cost effective "current combustion control technology" (as prescribed in the RHR)

- AEP/PSO may, if feasible, subsequent to the installation and fine tuning of the 'current combustion technology" and following a few years of operation, voluntarily offer to permit these units at a lower limit,

- Table VI-5, indicates SO_2 limits of 0.15 lbs/mmBtu and NO_x limits of 0.15 lbs/mmBtu for the Northeastern Power Station Units 3 & 4. AEP/PSO would note that these are keyed to "presumptive limits" established by the EPA in the RHR, for specific fuel and boiler type, typical of these units. These limits correspond to "cost effectiveness' determination made by the EPA and recommended for use by states as BART.

- AEP/PSO will meet the 0.15 lb/mmBtu limit for NO_x, per the RHR

- As discussed earlier in the general section of the comments, AEP/PSO wishes to revise its SO_2 offerings to satisfy a 0.55 lb/mmBtu BART limit. This revision is based on subsequent BART statutory five-factor analyses performed at ODEQ's request and benchmarking the cost effectiveness determination against EPA's average cost effectiveness criteria suggested in the RHR

- AEP/PSO requests the ODEQ to reflect the 0.55 lb/mmBtu SO_2 limit in Table VI-5 as BART emissions factor for the Northeastern Power Station, Units 3 & 4, in lieu of the 0.15 lb/mmBtu value

- AEP/PSO would note that incidental to meeting the 0.55 lb/mmBtu limit is the potential to meet a SO_2 control efficiency of 43% and visibility benefits at 4-Class 1 areas approximating to 41%, from modeling baseline conditions in the RHR

- As previously discussed, the ODEQ has the authority and it's within its purview to establish BART limits, based on cost effectiveness considerations. After assessing future regulatory outcomes and in support of RPG efforts, the ODEQ could always revisit imposition of newer SO_2 limits, subject to consideration of reasonable progress factors (that includes incremental cost of compliance and the time necessary for compliance) for these units

- AEP/PSO supports the flexibility in BART limit compliance timeline espoused in this Draft SIP which reads " (BART) Subject sources must achieve the BART emission standards referenced above.......within seven

(7) years from the date of submission of the Oklahoma Regional Haze SIP or within five (5) years of EPA's approval of the SIP, whichever is longer.

- AEP/PSO would note that the state BART rule "requires each source subject to BART to install and operate BART no later than 5 years after EPA approves this implementation plan revision" To avoid conflicting timeline language, AEP/PSO would recommend that the state rule OAC 252-100-8-75(e), be amended to be consistent with the Draft SIP language

- Table VI-6 lists Controls to be used to comply with BART

- AEP/PSO concurs with the LNB/OFA listing for NOx control at the gas-fired EGUs at Northeastern Power Station Unit 2 and the Southwestern Power Station Unit 3

- At the gas-fired Comanche Power Station Units 1 & 2, NOx control should be corrected to read DLNB, in lieu of LNB

- The SO2 controls for Northeastern Power Station Units 3 & 4 should be changed to reflect Low Sulfur use, which has been determined to be cost effective and provides visibility benefits at Class 1 areas of interest to the ODEQ

- AEP/PSO concurs with LNB/OFA listing for NOx control at the Northeastern Power Station, Units 3 & 4. This has been established by the EPA in the RHR as the "cost effective" approach for the fuel and boiler type, with significant visibility improvements. The RHR has provided detailed justification for not requiring post-combustion NOx control to comply with BART

- AEP/PSO concurs with the existing ESP for PM control as reflected in the Table VI-6

- Table VI-7 portrays SO2 BART-level Emissions Reductions from the 2002 Baseline. AEP/PSO would ask that the Total Reduction for the Northeastern Power Station, Unit 3 & 4 be corrected to reflect the Tons corresponding to BART limit of 0.55 lbs/mmBtu of 12,413 tons

- Table VI-11 portrays Visibility Improvement in the 98th Percentile with BART SO2 controls from Modeled Baseline conditions. AEP/PSO requests that the Visibility Improvement at Wichita Mountains, Caney Creek, Upper Buffalo and Hercules Glades be changed to the following to reflect the improvements attributable to Low Sulfur fuel (0.55 lb/mmBtu) use:

Wichita Mountains	–	0.50 delta dV
Caney Creek	_	0.51 delta dV
Upper Buffalo	_	0.38 delta dV
Hercules Glade	_	0.42 delta dV

Section VII, Long-term Strategy with Emission Reduction

- AEP/PSO agrees with the ODEQ statement that "because emissions from Oklahoma only insignificantly impair visibility at all other Class 1 areas, this long term strategy for achievement of reasonable progress goals in other Class 1 areas requires no further rules or actions from the DEQ".

- AEP/PSO applauds ODEQ's recognition that reduction in emissions inventories resulting from unit retirements, other regulatory activities, fuel switching etc, will have a direct bearing and positive impact on the RHR program implementation, especially as pertaining to the RPG needs in Class 1 areas. In that vein, AEP/PSO would request the State to guard against unjustified call for large and immediate emissions reductions (from in-state BART-eligible sources) to address RPG requirements as part of BART

- For consistency reasons, in Section VII- 3. Enforceability, the language in the last paragraph which reads" 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" should be modified to be consistent with the language in Section VI-C, Determination of BART Requirements for Subject sources.

- AEP/PSO requests the state rule OAC 252:100-8-75(e) be amended to reflect the language in Section VI-C

Section VIII. Modeling of Regional Haze in 2018

- Table VIII-2 projects an annual TPY increase of 32.86% in the state's Ammonia emissions inventory from the 2002 year. As previously stated, AEP/PSO requests the ODEQ to consider the complementary role of Ammonia in visibility impairing particulate formation. AEP/PSO sees the need for the ODEQ to address Ammonia control (in the near term) as also to cap Ammonia emissions for meaningful visibility reduction in the near term and into the future

- Section VIII B 2 Electric Generating Unit Projections, (based on IPM 2.1.9 to generate 2018 estimates to model future RPG goals), are probably outdated and thus the use of past projections may understate the RPG predictions. AEP/PSO would encourage the ODEQ to not lose perspective of future expected lower levels of SO2 and NOx and not be pressured into requiring very aggressive BART limits in the very near term. BART limits should be based on the five-factor analysis

Section IX. Reasonable Further Progress Goal

- AEP/PSO concurs with the ODEQ representation in this section that the RFP goal is to show progress towards milestones goals that are "reasonable" and within its control

- AEP/PSO would note that the RHR gives a state with a Class 1 area, the flexibility in determining the RFP goal for that area. These include, extension to the glide path (beyond the 60-year point) based on the state's demonstration, applying reasonable progress factors that considers cost of compliance and the time necessary for compliance to show that the 60-year period is not reasonable and that the longer period selected by the state in reasonable.

- In support of its analysis, the ODEQ has provided a good discourse on its reasonableness determination and inability to meet the Uniform Rate of Progress established for its Class 1 area, even with the elimination of all anthropogenic sources within Oklahoma.

- Section IX A is optimistic about achieving its RFP goal derived from modeling results with estimated emissions for 2018. AEP/PSO would tend to agree with this ODEQ optimism, recognizing that the modeling was performed in the 2004/05 period when future emission projections were based on business-as-usual and overstated. AEP/PSO would however caution the ODEQ against being pressured into having its BART-eligible sources to submit to extreme levels of reduction too soon, by interpreting statutory factors differently

- Section IX B, Reductions Required to Meet the Uniform Rate of Progress correctly interprets the RHR language which does not require the ODEQ to compensate for the lack of control in Texas, other states and foreign countries. AEP/PSO agrees that it would be inappropriate and unreasonable to require additional controls of its state sources (as part of BART), beyond what is determined to be cost effective

- Section IX C. Control Simulations, addresses "control-sensitivity evaluation of the effect of reducing point-source emissions of NOx and SO2 only with existing emissions-control technology" in support of meeting the Uniform Rate of Progress. AEP/PSO was actively involved in these deliberations as part of CENRAP and was not supportive of the process, especially with regard to the cost effectiveness determinations and agrees with the ODEQ sentiments that the cost-effectiveness calculations were not predicated on true retrofit costs

❖ Section IX D. Factors for Consideration correctly identifies the key components in the "reasonableness determination in support of meeting reasonable progress goal targets". AEP/PSO concurs with the ODEQ (on the lack of merit in requiring controls beyond what is required to meet "cost effective" BART limits) and "compelling facilities to expend large amounts of capital on pollution reduction technology likely would cause some facilities to cease operation and further compound unemployment and other economic problems in the communities".

Comments to the Applicable Contents in Appendices

Appendix 6-1, Oklahoma's BART Rule and Administrative Materials

❖ AEP/PSO would request the following amendments be made:

- 252:100-8-75(a)(1) be amended to read: "The determination of BART must be based on an analysis of the best system of continuous emission reduction achievable for each BART-eligible source that is subject to BART, based on a five-factor analysis"

- 252:100-8-75(a)(2) be amended to read: BART would be an emission limit based on the determination in (a)(1) above

- 252:100-8-75(a)(3)(e) be amended to read: The owner or operator of each BART-eligible source subject to BART shall meet applicable emission standards determined in (a)(2) above within (7) years from date of submission of the Oklahoma Regional Haze SIP or within five (5) years of EPA's approval of the SIP, whichever is longer

- 252:100:-8-76, Permit requirements be amended to read: The BART requirements for any BART-eligible source that is subject to BART shall be submitted to the Director in an application for a permit modification pursuant to OAC 252:100-8-7-2 no later than 3 months after the EPA approval of the ODEQ SIP

Appendix 6-4, BART analysis for each facility required to install BART

BART Application Analysis for AEP/PSO Comanche Power Station

- Page XV, Section IV. Best Available Retrofit Technology (BART) , Table 2, Proposed BART Control and Limits

  - The BART Technology column for Comanche Unit 1 and Comanche Unit 2 should read DLNB, instead of Low NOx Burners

  - AEP/PSO agrees with ODEQ's findings that the installation and operation of the BART determined NOx control, new DLNB, meets the statutory requirements of BART

  - AEP/PSO agrees with the stipulation on Page XXVIII that "with installation of the BART controls, the duct burners will no longer be authorized to operate

  - Page XXVIII, Section VI. Operating Permit:

  - Item 1. Need to delete reference to duct burners

  - Item 1.b. should be modified to read "Each existing affected facility shall meet applicable emission standards determined within (7) years from date of submission of the Oklahoma Regional Haze SIP or within five (5) years of EPA's approval of the SIP, whichever is longer

BART Application Analysis for AEP/PSO Northeastern Power Station

- Page LXXII, Table 1: Northeastern Power Plant Operating Parameters for BART Evaluation

  - The Baseline Actual Emissions listing for SO2 for Northeastern Unit 3 and Northeastern Unit 4 should be corrected to read 0.55 lb/mmBtu and the corresponding Lb/Hr should be 2865 and 2865 respectively

  - Page LXXIV, Table 2 BART Control and Limits

  - The column for SO2 BART Emission Limit for Northeastern Unit 3 and Unit 4 each should reflect 0.55 lbs/mmBtu (30-day rolling average)

  - The column BART Technology for Northeastern Unit 3 and Unit 4 each should reflect Low S fuel

  - AEP/PSO will provide the BART assessment report in support of the BART limit offered and the visibility report separately

- Page CII - AEP/PSO agrees with the ODEQ's finding that the installation and operation of New LNB/OFA for Northeastern Units 2, 3 and 4 meets the statutory BART for NOx with limits of 0.28 lb/mmBtu for Unit 2 and 0.15 lb/mmBtu for each of Units 3 & 4, on a 30-day rolling average

- The language inadvertently refers Units 3 & 4 as Units 1 & 2 and need to be corrected. AEP/PSO agrees with the ODEQ's findings that LNB/OFA plus SCR <u>is not determined</u> to be BART for NOx control for Units 3 and 4

- AEP/PSO would add that post combustion control for NOx was not deemed BART by the RHR based on "cost-effective" analysis by the EPA. AEP/PSO performed SCR analysis at the ODEQ's request

- Page CIII – SO2 – AEP/PSO will supplement its analysis which would demonstrate that a New Dry FGD is not cost effective and will provide information in support of meeting a 0.55 lb/mmBtu on a rolling average using low S fuel

- AEP/PSO would request that the ODEQ make modification to its Draft SIP subsequent to the submittal of a report which would justify SO2 emission limit of 0.55 lb/mmBtu as BART for Northeastern Units 3 & 4

- Page CIV, Table 17, Unit-by-unit BART determinations needs to be corrected as follows:

- Unit 3 and Unit 4 SO2 control should reflect Low S fuel, instead of Dry FGD with SDA
- Emission rate in lb/mmBtu (for SO2) should be changed to 0.55 lb/mmBtu in lieu of 0.15 lb/mmBtu
- Emission Rate in lbs/hr (for SO2) should be changed to 2865 in lieu of 716 lbs/hr
- Emission Rate in TPY (for SO2) should be changed to 12552 in lieu of 3,137 TPY

- <u>Page CVI, </u>Item s. should be modified to read "Each existing affected facility shall meet applicable emission standards determined within (7) years from date of submission of the Oklahoma Regional Haze SIP or within five (5) years of EPA's approval of the SIP, whichever is longer"
- Item v. should be modified to read "Units 3 and 4, affected facilities, shall meet the BART emissions limits as shown below"

- Item w. should be modified to read "the permittee shall maintain the controls (Low-NOx burners, overfire) and establish procedures to ensure the controls are properly operated

- Page CVII, Table for EU ID# 3 and 4, the columns for SO2 Emission Limit should indicate 0.55 lb/mmBtu

BART Application Analysis for Southwestern Power Station, Unit 3

- AEP/PSO agrees with ODEQ's findings that the installation and operation of the BART determined NOx control, new LNB/OFA meets the statutory requirements of BART

  - Page CLXXXIX , Sentence before Section V. Construction permit needs to be corrected to drop reference to FGR. It should read: "The Division considers the installation and operation of the BART determined NOx controls, new LNB with OFA, to meet the statutory requirements of BART.

  - Page CXC Section VI. Operating Permit, Item 1.uu. Should be modified to read "Each existing affected facility shall meet applicable emission standards determined within (7) years from date of submission of the Oklahoma Regional Haze SIP or within five (5) years of EPA's approval of the SIP, whichever is longer

We look forward to further discussions concerning our comments.

Sincerely,

Howard Ground

Howard L. Ground
Manager Governmental & Environmental Affairs

Cc: S.Solomon
J.McManus
J.Henry
D.Dharma

wfec
western farmers
electric cooperative

P.O. Box 429 • Anadarko, Oklahoma 73005-0429 • (405) 247-3351 • www.wfec.com

A Touchstone Energy® Cooperative

RECEIVED
DEC 16 2009
AIR QUALITY

Mr. Eddie Terrill, Director
Air Quality Division
Oklahoma Department of Environmental Quality
707 N. Robinson
Oklahoma City, OK 73101

RE: Oklahoma Department of Environmental Quality ("DEQ")
Draft Regional Haze Implementation Plan Revision
Submittal of Formal Comments

Dear Mr. Terrill:

Western Farmers Electric Cooperative ("WFEC") has conducted an initial review of the DEQ's proposed draft Regional Haze Implementation Plan Revision ("Revision") dated November 13, 2009 regarding visibility impacts to the Wichita Mountains Wilderness Area ("WIMO") (Oklahoma's only Class I area) and the DEQ's proposed path toward achieving compliance with the nationwide program promulgated by the U.S. Environmental Protection Agency ("EPA"). WFEC appreciates the hard work and detailed analysis conducted by the DEQ as evidenced in the Revision. WFEC further appreciates this opportunity to review and comment on the Revision during the initial drafting stages.

Based upon an initial review, WFEC has identified the following issues of concern regarding the Revision (which are discussed below in more detail) which it requests the DEQ address and resolve prior to finalizing the Revision:

1. The DEQ has determined the impact of out-of-state emissions (primarily from the State of Texas) on visibility in the WIMO are significant. Conversely, Texas recently submitted its Regional Haze SIP Revision to EPA and therein indicated emissions originating from Texas do not impact visibility in the WIMO. Therefore, there appears to be a significant disagreement between the findings from each State. How does the DEQ propose to resolve this issue?

2. Notwithstanding the fact that Oklahoma would be unable to meet the Uniform Rate of Progress ("URP") toward meeting the ultimate visibility goal specified by EPA if all point sources of emission within Oklahoma were removed, the Revision places significant emission reduction burdens on Oklahoma sources via BART while sources located in Texas (whose emissions significantly contribute to visibility impairment at the WIMO) appear to escape further control. Did the DEQ advise Texas that additional emission reductions from Texas sources would not be needed to help Oklahoma meet the WIMO reasonable progress goals, and if so, on what basis was such determination made?

As referenced in the Revision, EPA's Regional Haze Rule (40 C.F.R. Part 51, Subpart P) was aimed at achieving national visibility goals by the year 2064 and address the combined effects on visibility from various air emission sources over broad geographical regions. In doing so, EPA identified the key role of pollutant transport (both interstate and internationally) in contributing to regional haze in Class I areas located in the U.S. and therefore designated five (5) regional planning organizations to assist in the interstate coordination and cooperation necessary to effectively address visibility in designated Class I areas.

The Revision currently identifies various air pollutant emissions from other states as well as international transport as having visibility impacts on the WIMO:

> Sections A, B, C, D, and E of this chapter discuss in detail modeling methods and protocol used by DEQ in developing the assessment. Results primarily attribute sulfureous aerosol, nitrate aerosol, and elemental carbonaceous particulate to anthropogenic sources; organic carbonaceous particulate, fine soil particulate, and coarse particulate concentrations are attributed to natural and/or area sources. *For most pollutants, the majority of visibility-impairing pollutants originate outside of Oklahoma*; prevailing winds transport a considerable proportion of visibility impairing aerosols from Texas, and more than one-tenth of visibility impairment at the Wichita Mountains results from international transport.[1] (Emphasis added)
>
> ... This modeling attributes visibility impairment at the Wichita Mountains mainly to anthropogenic emissions of sulfureous and nitrate pollutants. *Sources in Oklahoma contribute less than one-seventh of visibility impairment at the Wichita Mountains; emissions from Texas alone account for almost twice the impairment as those from all of Oklahoma*.[2] (Emphasis added)
>
> As Table V-8 indicates, sulfureous emissions clearly most importantly impair visibility at the Wichita Mountains. Nitrate particulate matter forms from NOx emissions but occurs predominantly during the winter months; sulfureous aerosol comprises a plurality during the rest of the year. Organic carbonaceous aerosols also contribute significantly to visibility impairment at the Wichita Mountains. *Texas sources bear culpability for the largest proportion of visibility impairment. In every category except coarse particulate matter, sources in Texas (and other states) notably contribute more than those within Oklahoma do.* Several other states each emit sulfureous aerosols which impair visibility at the Wichita Mountains more than emissions from all Oklahoma sources do.[3] (Emphasis added)
>
> Table V-8 shows some contribution from sources in southern Canada, northern México, and especially the boundary conditions outside the CENRAP modeling domain. The boundary conditions include particulate from much of central and all of southern México, including Ciudad México (Distrito Federal), the Mexican Yucatán Peninsula, Mesoamerica, the Caribbean region, Africa, the People's Republic of China, and other Asian and international sources. *International transport contributes more than one-tenth of the regional haze on the worst quintile of days at the Wichita Mountains*.[4] (Emphasis added)

[1] *See* "Regional Haze Implementation Plan Revision", *November 13, 2009 Draft* ("Revision"), at p. 48.
[2] Revision at p. 49.
[3] Revision at p. 66.
[4] Revision at pp. 67, 68.

Based on the above and the fact that "... even the elimination of all anthropogenic sources within Oklahoma is not sufficient to comply with uniform rate of progress", the DEQ concluded "any effective strategy for managing visibility impairment at the Wichita Mountains must address outside sources including regional and international transport."[5,6] However, the Revision is silent as to how such outside sources will be addressed.

Notwithstanding the above, the Revision identifies emissions reductions from Oklahoma sources sufficient to meet the reasonable progress goal for the WIMO set forth in 40 C.F.R. § 51.308(d)(3)(ii), in part, by requiring the installation of Best Available Retrofit Technology ("BART") for any BART-eligible source determined to cause or contribute to visibility impairment at the WIMO. However, the same fails to address the significant visibility impacts on the WIMO caused by sources located outside the State of Oklahoma. Accordingly, the required emission reductions identified in the Revision will come at a significant and unjustified cost to Oklahoma industry. As a result, industry currently located in or seeking to locate in Oklahoma will be placed at a significant economic disadvantage at a time when both the State and national economies are struggling.

The State of Texas previously submitted its Regional Haze SIP Revision to EPA in March 2009. WFEC has obtained and reviewed the same to determine what, if any, emission reductions will be placed on Texas sources whose emissions contribute to visibility impairment in the WIMO. In doing so, WFEC learned Texas had determined that its emissions did not impact the WIMO:

> The TCEQ reviewed CENRAP modeling to assess which Class I areas in other states might be impacted by Texas' emissions. Modeling indicated that Texas impacts Breton Wilderness Area in Louisiana, the Great Sand Dunes in Colorado, and several Class I sites in New Mexico. *The TCEQ also consulted the adjacent states in which the modeling data indicated no significant impact by Texas, including Arkansas, Missouri, and Oklahoma*. ...[7] (Emphasis added)

Further, it is clear that Texas was aware the WIMO was approximately forty percent (40%) short of meeting the 2018 point on the Uniform Rate of Progress glide path.[8] More importantly, it appears that Texas consulted with Oklahoma and was advised no additional emission reductions from Texas sources would be needed to help Oklahoma meet the WIMO reasonable progress goals.[9] Such statement does not appear to reflect

---

[5] Revision at pp. 96. *See also* "Oklahoma's Wichita Mountains Wilderness Area Regional Haze Planning", Oklahoma's WIMO Consultation Plan, which very succinctly states the following at p. 7:

> ... Thus far, no scenario has resulted in Oklahoma meeting its glide path goal for 2018 through reevaluation of background levels or controlling emissions within state borders. Source Apportionment Modeling used to apportion culpability to individual source categories and geographic regions indicates that removal of the impact of all point sources within Oklahoma would not result in our achieving the 2018 reduction goal.

[6] Revision at p. 48.

[7] *See* "Revisions to the State Implementation Plan (SIP) Concerning Regional Haze", Texas Commission on Environmental Quality, February 25, 2009 ("Texas SIP"), at p. 4-2.

[8] Texas SIP at p. 8-17.

[9] Texas SIP at p. 11-7 wherein the following is stated:

the magnitude of Texas' emissions and/or their significant impacts on visibility in the WIMO as previously referenced.

Additionally, Texas' Regional Haze SIP Revision contained a detailed BART review and analysis wherein additional controls and their projected improvements (based on an "effectiveness ratio") on visibility in Class I areas were evaluated. Thereafter, due to the poor cost-effectiveness of additional, reasonable point source controls, Texas determined additional controls for regional haze were not appropriate.[10]

> The TCEQ used the CENRAP modeling to estimate the impact that the control strategy would have on the Class I areas impacted by Texas' emissions. The CENRAP conducted a modeling analysis presuming an aggressive set of additional controls above and beyond CAIR and BART. Texas used the results of this modeling analysis to determine an effectiveness ratio for NOx and SO2 reductions. The effectiveness ratio provides an estimate of improvement in visibility for every ton of NOX and SO2 reduced. Using these ratios, the TCEQ was able to develop an order of-magnitude estimate of the likely visibility improvements resulting from the point source control strategy (see Table 10-6: *Estimated Haze Index Improvements for Affected Class I Areas*). ...[11]
>
> As Tables 10-5 and 10-6: *Estimated Haze Index Improvements for Affected Class I Areas* show, *the analysis identified controls costing well over $300 million, yet the projected benefit of those controls on each Class I is not perceptible*. A single (1.0) deciview is the smallest perceptible improvement in visibility. In the TCEQ's Best Available Retrofit Technology (BART) rule, the state considered 0.5 deciviews as the threshold under which a facility was not considered to meaningfully contribute to visibility impairment. A difference improvement of 0.05 deciviews is well within the uncertainty of the modeling techniques and is much lower than perceptible.[12]
>
> *At a total estimated cost exceeding $300 million and no perceptible visibility benefit, Texas has determined that it is not reasonable to implement additional controls at this time.* All units in Texas that met the emissions over distance threshold were assessed. (Emphasis added)[13]

Texas thereafter cited to impacts associated with international transport and indicated the URP assumed all reductions needed to meet the same would come from Texas; however, such reductions would require "significant over-control" to compensate for the impacts of international transport.[14]

> Arkansas, Missouri, and Oklahoma have each included Texas in consultations concerning regional haze impacts on the Class I areas in these states. The TCEQ reviewed CENRAP PSAT modeling to assess how Texas' emissions might affect other states' Class I areas. Pursuant to this review, Texas has written to Arkansas, Missouri, Oklahoma, New Mexico, Louisiana, and Colorado to ask whether emission reductions projected in Texas by 2018 are sufficient to meet Texas' apportionment of the impact reduction needed to meet the reasonable progress goal for each Class I area in each state. *Texas has completed its consultation with Louisiana, Arkansas, Missouri, Oklahoma, and Colorado, and none of these states has asked Texas for further emission reductions to help the state meet its reasonable progress goals for its Class I area(s).* ... (Emphasis added)

[10] Texas SIP at p. 10-12.
[11] Texas SIP at p. 10-5.
[12] Texas SIP at p. 10-6.
[13] Texas SIP at p. 10-8.
[14] Texas SIP at p. 10-12.

Regarding the WIMO, the same factual circumstances can be applied. Emission reductions identified in the Revision should not require "significant over-control" of Oklahoma sources to compensate for visibility impacts at the WIMO caused by out-of-state sources. To do so preclude national consistency and/or uniformity in the application and determination of regional haze and could potentially violate the concept of fundamental fairness.

Following further review and analysis of the Revision, WFEC will, as necessary, submit additional comments to identify any additional issues which it identifies regarding the Revision. Again, WFEC appreciates the opportunity to review and comment on the Revision.

Sincerely,

Gerald Butcher

SUMMARY OF COMMENTS AND STAFF RESPONSES FOR PROPOSED REVISION TO THE OKLAHOMA REGIONAL HAZE STATE IMPLEMENTATION PLAN

COMMENTS RECEIVED PRIOR TO AND AT THE DECEMBER 16, 2009 PUBLIC HEARING

Written Comments
U. S. Environmental Protection Agency, Region 6 (EPA) in a letter dated December 15, 2009, signed by Carrie Paige for Guy Donaldson, Chief, Air Planning Section

1. **COMMENT:** Although on page 68, ODEQ states that Appendix V, Section 2.1(b) through (h), are included in Appendix 6-1, it does not appear that is the case. ODEQ should ensure, with the submittal of the final SIP, it demonstrates it has followed the requirements of Appendix V to Part 51.

   RESPONSE: DEQ has added the required administrative materials.

2. **COMMENT:** On page 35, ODEQ states that for the purposes of calculating natural conditions, it considered all organic carbonaceous particulate, coarse matter, and fine soils as natural and all sulfureous, nitrate, and elemental carbon particulate as anthropogenic. This assumption ignores fine soil contribution from agricultural practices, such as wind-blown dust from tilled fields. Historically, this has been a significant source of fine soil.

   RESPONSE: It appears that EPA **may** misunderstand the purpose of this consideration. This consideration applied to "pseudo-natural" conditions, where the prefix "pseudo-" means false, deceptive, and sham. DEQ included these pseudo-natural conditions to highlight the three categories of particulate for which DEQ possesses enough evidence to attempt to regulate in this implementation plan revision. DEQ included this calculation to enlighten the reader regarding the efficacy of a strategy designed to reduce emissions contributing to these three categories of other particulate matter.

   DEQ concurs with EPA regarding the accounting of this contribution but finds this contribution relatively small and impossible to isolate at the Wichita Mountains. DEQ will address these sources in comprehensive periodic revisions to this implementation plan under 40 CFR § 51.308(f).

3. **COMMENT:** On page 32, ODEQ expands this discussion as it relates to fire, stating it assumed an overwhelming majority of organic aerosols originate from natural sources or fires. It is unclear whether this assumption ignores organic carbonaceous contributions from non-natural sources, such as agricultural fires and fires used to clear rangeland. Because of the economic component associated with these fires, it is unclear how they can be considered natural. Consequently, Region 6 feels these assumptions have not been adequately justified.

   RESPONSE: The final paragraph in Section III.A.3 has been deleted in its entirety.

4. **COMMENT:** Also, these assumptions impact the requirement in 40 CFR 51.308(d)(3)(iv), which requires ODEQ identify all anthropogenic sources of visibility impairment considered by it in developing its LTS, including consideration of major and minor stationary sources, mobile sources, and area sources.

RESPONSE: DEQ identifies all sources of emissions that degrade visibility in Section IV, which reinforces the assumptions concerned. DEQ considered all anthropogenic sources in developing the long-term strategy. DEQ will not control fires and various other sources as part of this implementation plan revision for various reasons, including their relatively small contribution to total visibility impairment and the administrative difficulty associated with such controls.

5. **COMMENT:** On page 104, ODEQ states "Despite their prominence in the emissions inventory, agricultural burning and wildfires in Oklahoma do not contribute significantly to regional haze at the Wichita Mountains nor at any other Class I area." However, Region 6 notes that according to Tables IV-1, IV-2, and IV-8, fire emissions account for approximately 33% of Oklahoma's PM 2.5 emissions inventory with agricultural burning itself accounting for approximately 23%. It would therefore appear that anthropogenic sources of biomass burning emissions are a significant contributor to the state's PM 2.5 emission inventory. Especially when it is considered that much of these emissions usually occur within a few weeks in the spring or summer and are not evenly spread out over the year.

RESPONSE: DEQ presumed that most particulate matter emitted from fires primarily takes the forms of organic and elemental carbonaceous particulate. Measurements of these components of visibility impairment at the Wichita Mountains do not indicate that these components of particulate matter predominate on many days without prescribed burning on the Wildlife Refuge or catastrophic fires in the vicinity.

Table IV-1 does not disaggregate fire emissions from any emissions category. Table IV-2 lists all emissions from fire area sources, totaled according to category. The cited statistics come only from Table IV-8, which Environmental Protection Agency slightly misinterprets. Extensive burning in the Flint Hills region of Kansas and Oklahoma generally occurs during periods of southerly flow near the surface, and few Class I areas lie downwind of these fires. Agricultural grass fires alone account for 23% of direct $PM_{2.5}$ emissions. The "all other" fire area sources classification in the table includes various other agricultural fires.

Despite the large proportion of directly emitted $PM_{2.5}$ attributed to fires, DEQ does not believe that smoke from these fires contributes significantly to regional haze at the Wichita Mountains on the overwhelming majority of days. DEQ uses the Interagency Monitoring of Protected Visual Environments (IMPROVE) protocol to measure regional haze in accordance with 40 CFR § 51.308(d)(4). This monitoring technique does not consider smoke plumes aloft as regional haze or any other form of visibility impairment in contrast to the definition of visibility impairment in 42 USC § 7491(g)(6). DEQ follows the EPA's lead in not addressing atmospheric discoloration from smoke plumes aloft under as visibility impairment presently. Numerous pollutants emitted as gases not directly emitted as $PM_{2.5}$ convert to particles in the atmosphere, also contributing to regional haze. Anthropogenic sources other than fires emit a considerable majority of these gases.

Fires generally occur on days with atmospheric conditions that limit smoke spreading at the surface. Most smoke usually forms plumes aloft and generally travels above monitoring equipment. Easily identifiable smoke reached the Wichita Mountains in any considerable quantity on only a few monitored days. These events included known burning on the Wichita Mountains Wildlife Refuge and catastrophic fire.

6. **COMMENT:** Region 6 understands that ODEQ is presently developing a smoke management plan. We view this as very important tool in the control of these emissions and urge ODEQ to work with us in the finalization of this important document.

   RESPONSE: DEQ will work with EPA as it develops the smoke management plan.

7. **COMMENT:** Section 51.308(d)(1)(iv) requires that ODEQ consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment for the Wichita Mountains. According to Tables V-1-V-6, and as noted on page 66, Texas accounts for more sulfurous, nitrate, organic carbonaceous, elemental carbonaceous, and fine soil particulate sources of light extinction to the Wichita Mountains than do those source in Oklahoma, and is right behind Oklahoma in coarse particulate. Table V-8 also indicated the sulfurous sources from Louisiana and Indiana also account for more light extinction than do the sulfurous sources in Oklahoma. Appendix 10-1 contains several consultation letters between ODEQ and neighboring States regarding ODEQ's consultation efforts. However, despite the obvious contribution from Texas sources to the visibility degradation to the Wichita Mountains, it does not appear that ODEQ actually requested reductions from specific sources within Texas – only that it be consulted on BACT analyses for sources within 300 kilometers from the Wichita Mountains. We urge Oklahoma insure that Texas is aware its sources impacts and encourage reductions as necessary.

   RESPONSE: DEQ's consultations with Texas are accurately documented in this SIP revision and information provided during those consultations clearly indicate Texas sources contribute significantly to visibility impairment at the Wichita Mountains.

8. **COMMENT:** ODEQ should include in Section X and in Appendix 10-1 the details concerning its consultation with Louisiana, or discuss why it did not feel sources in Louisiana are not reasonably anticipated to cause or contribute to visibility impairment at Wichita Mountains, in fulfillment of Section 51.309(D)(1)(iv).

   RESPONSE: DEQ's consultations with Louisiana are accurately documented in this SIP revision and information provided during those consultations clearly indicated the contributions from Louisiana sources to visibility impairment at the Wichita Mountains.

9. **COMMENT:** On page 69, ODEQ discusses how it identified which sources were BART-eligible, stating, "DEQ reviewed its emissions inventory and followed the steps listed in Subsection II.A of Appendix Y to 40 C.F.R. Part 51 to derive a list of BART-eligible sources." However, no other information was located that describes the steps ODEQ took to make this determination. ODEQ should expand this discussion, making particular reference to information sources (e.g., permit databases, surveys, etc.) and how it ensured all BART-eligible sources were identified.

   RESPONSE: Additional information has been added to the BART chapter.

10. On page 71, Table VI-3 lists BART-eligible sources that were granted waivers from BART via proposed permitted emission limits. The actual waivers in Appendix 6-3, all contain essentially the same language:

"The active Title V permit will now be modified to include requirements that the facility comply with the proposed changes/limits in the application within five years of the Regional Haze SIP approval by EPA. Also to be included, will be a requirement that the facility modify the operating permit to incorporate the proposed method of compliance with Appendix Y to Part 51, V. Enforceable Limits. The operating permit shall be modified no later than 6 months prior to the SIP approval."

Regarding this, ODEQ should address the following:

a) **COMMENT:** No information was provided that indicates what controls or practices would be necessary to comply with these new permit limits. ODEQ should ensure that if compliance is via relatively uncomplicated work practices or operational modifications that can be done in a relatively short period of time, the full five years is not granted. This is necessary in order to comply with 51.308(e)(1)(iv), which requires "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."

   RESPONSE: Additional information has been added on the BART waivers based on new emission limits. As previously indicated in the SIP, the Part 70 (Title V) permit for each of these facilities has or will be modified to include requirements necessary to qualify for the waiver from BART. The modified permit and/or accompanying evaluation memo as appropriate will specify the new permit limits, any controls or practices necessary to meet the limits, and timelines for implementation. For changes that entail a "major modification" of the Part 70 permit, the normal opportunity for EPA and public review of and comment on these permit changes will be provided. DEQ anticipates that each of these permits will be modified "…no later than 6 months prior to the SIP approval" as stated in the waivers.

b) **COMMENT:** ODEQ should provide all modeling and technical evaluations necessary to document the amount of reductions necessary for these facilities to fall under the BART threshold of 0.5 dv.

RESPONSE: All modeling and technical evaluations documenting these reductions are in the applications and will be included DEQ's evaluation memo for the Part 70 permit modification. This information has been provided to EPA and the FLMs, and is available for review online and/or in DEQ files. DEQ believes that including copies of all of these files in the SIP submittal is unnecessary, considering the documentation currently provided in the SIP and the status of these facilities.

11. On page 71, ODEQ makes the following statement regarding these facilities and BART enforcement:

"DEQ will issue enforceable Part 70 air quality permits requiring BART-eligible sources subject to BART to: (1) install BART and achieve the associated BART emission standards; or (2) "achieve greater reasonable progress toward natural visibility conditions" through an approvable alternative as provided for in 40 CFR § 51.308(e). Subject sources must achieve the BART emission standards referenced above or achieve the "greater reasonable progress" referenced above within seven (7) years from the date of submission of the Oklahoma Regional Haze SIP or within five (5) years of EPA's approval of the SIP, whichever is longer."

Regarding this, the following comments apply:

a. **COMMENT:** Any future alternative to BART, as contemplated under 40 CFR 51.308(e)(2), would require a SIP modification.

   RESPONSE: The final BART Determinations and the SIP revisions spell out BART with, where applicable, corresponding Contingent SO_2 BART Determinations and Greater Reasonable Progress Alternative Determinations. As a result, the referenced language has been modified. DEQ acknowledges that a SIP modification would be required for any BART changes or alternatives following EPA's approval of this SIP Revision.

b. **COMMENT:** Region 6 suggests the language "achieve greater reasonable progress," which is apparently offered as an alternative to the BART emission limits proposed in the SIP, be dropped to avoid confusion with the reasonable progress requirement of 51.308. If a permit condition results in less SO2, NOx, or PM control than was provided for in the SIP, it would require a SIP modification.

   RESPONSE: Although the specific language referenced by EPA's comment has been modified in the updated SIP Revision, DEQ believes that it has correctly applied the "greater reasonable progress" phrase as it is used in 40 CFR § 51.308(e)(2). *See also previous response.*

c. **COMMENT:** A schedule of compliance with BART that provides for the operation of BART controls later than five years from EPA's approval of the SIP would not be in compliance with 51.308(e)(1)(iv). Note similar language is on page 79.

   RESPONSE: The specific language referenced by EPA's comment has been modified in the updated SIP Revision, and the revised BART Determinations specify appropriate timelines.

d. **COMMENT:** The above comment concerning the review of the modeling not withstanding, ODEQ should understand that Region 6 will not be able to approve the Oklahoma regional haze SIP until we are assured there is an adequate enforcement mechanism in the SIP to ensure these sources are no longer subject to BART.

   RESPONSE: DEQ is confident that the Part 70 permit modifications (in the context of the Part 70 Program), as referenced in the SIP, will constitute an adequate enforcement mechanism. In addition, Appendix 6-5 contains enforceable Regional Haze Agreements that cover certain BART-subject facilities.

12. **COMMENT:** ODEQ should discuss why the BART NOx limit for the AEP/PSO Southwestern power station unit 3 is 0.45 lbs/MMBtu, and not a lower value. It appears from an examination of EPA's CAMD database, that the historical annual NOx emission rates from this facility for each year from 2000 – 2008 (except for 2008), are already lower than the proposed controlled BART rate, even considering the BART rate is a 30 day average.

RESPONSE: PSO is required to establish final emission limits for the BART source in the construction and operating permits. For the purposes of this evaluation AEP-PSO was unable to obtain lower guarantees from vendors for these specific boilers. DEQ would agree that average annual emissions should ultimately be lower than these conservative estimates.

13. **COMMENT:** ODEQ should discuss why the AEP/PSO Northeastern power station units 3 and 4, should not have a lower proposed BART SO2 limit than the presumptive limit of 0.15 lbs/MMBtu.

RESPONSE: After considering the comments including cost received, the portion of the Regional Haze SIP and/or attached BART determination(s) relevant to the above comment(s) has been modified or removed. Consequently, the above comment has been addressed and/or is no longer applicable.

14. **COMMENT:** On page 76, ODEQ discusses additional information received for the OG&E Sooner and Muskogee coal fired EGUs. OG&E increased its cost effectiveness calculations for Dry FGD-SDA to a range of $9,625 to $10,843 per ton of SO2 removed and to a range of $10,271 to $11,490 per ton of SO2 removed for Wet FGD. Region 6 has reviewed the information that was provided for public review. Based on cost estimates we have for other similar units, we feel these cost are significantly inflated. We question the assumptions in cost that have been made in general and the cost assumptions for annual operating costs, including administrative costs, which are significantly out of proportion with other cost analyses for similar control installations. Region 6 understands the data to support this cost estimate has been identified by the source as proprietary in nature. EPA Administrator Jackson's priorities for regulatory decisions are they be transparent and meet the requirements of the law. Therefore, these principles of transparency and rule of law are ones Region 6 wants to ensure are met in this process. Therefore, we cannot base a decision regarding BART on data that is not available for public review. Because of the projected visibility benefits to multiple Class I areas that would result from the control of SO2 emissions at these facilities, the lack of support for OG&E's figures, and our feeling the true installed costs of these controls are much lower, Region 6 would likely not be able to approve the Oklahoma regional haze SIP without these controls. We note that the U.S. Fish and Wildlife have provided more detailed comments on the OG&E and PSO BART analyses. We share many of the concerns that they raised, but did not think it necessary to be as detailed in this comment letter.

RESPONSE: OG&E provided comments at the public hearing in response to this concern. OG&E has also supplemented its BART-related applications for Part 70 permit modifications with additional data. The documents have been provided on the DEQ website and submitted directly to Region 6. ODEQ agrees that the original cost calculations were inflated. The final BART determinations are based on the more accurate revised estimates.

15. **COMMENT:** One of the items that is briefly mentioned is that for some BART-eligible sources, no BART reductions were assumed in the Regional Modeling. It would be helpful to have a table summarizing for each BART-eligible source, what emission rates were assumed in the RH modeling.

RESPONSE: A preliminary draft table reflecting the emissions of BART-subject units used in the Regional Haze modeling has been assembled. Adding data to the table to reflect the emissions of BART eligible units used in the Regional Haze modeling would be an additional significant task. DEQ recognizes that the emissions resulting from the BART Determinations differ significantly from modeled emissions, and without additional analysis such a table would not be particularly relevant. Therefore, time restraints preclude including such a table in the BART chapter at this time. Further, emissions used in modeling reflect projected actual emissions rather than permitted potential emissions. Such comparisons, absent an understanding of facility operations, are of limited use.

16. **COMMENT:** An additional table indicating if the source was subject to BART, or was able to model out of BART and/or include the final emission rates that are being made federally enforceable (either through permitting, or other methods).

RESPONSE: This information is available in our SIP.

17. **COMMENT:** While the zero-out modeling bounds the impact, it would helpful to have a summary of additional emission rate changes that have not been take into account in the RH modeling analysis.

RESPONSE: While such a table would be interesting, time restraints preclude developing an alternative inventory and necessary cross references for a true comparison.

18. **COMMENT:** Within the body of the text in its reasonable progress section, beginning on page 96, ODEQ should provide references for the data contained in all the tables and figures (e.g., Table IX-1 Figure IX-1) that direct the reader to where the data can be found.

RESPONSE: In Table IX-1 and Figure IX-1, the implementation plan revision earlier defines and discusses the observations, baseline visibility impairment, and natural visibility conditions. The reasonable progress goal for 2018 derives from Community Multi-scale Air Quality modeling from CENRAP as described in Chapter VIII of this implementation plan revision. DEQ staff extrapolated the remaining quantities from the reasonable progress goal for 2018.

19. **COMMENT:** On page 99, ODEQ presents data in Table IX-3, that essentially shows the difference between its Reasonable Progress Goal (RPG) and the Uniform Rate of Progress (URP) is approximately equal to the visibility impact from sources outside of Oklahoma. Regarding this, ODEQ makes the statement: "The model-extracted data in Table IX-3 suggest that even complete elimination of all anthropogenic emissions in Oklahoma likely would fail to meet this uniform rate of progress." This zero-out run of Oklahoma's emissions assumes no additional changes in upwind states. This is not a realistic assumption and it does bias the conclusion that removal of all Oklahoma sources would still likely fail to meet the uniform rate of progress goals. Further reductions in upwind states in addition to local measures could yield a result meeting the uniform rate of progress goal.

RESPONSE: Table IX-3 shows the reasonable progress goal and the uniform rate of progress at the Wichita Mountains and the difference in visibility impairment between these rates in 2018. The visibility impairment attributable to sources outside Oklahoma, however, considerably exceeds the difference between these rates, whereas this difference likely slightly exceeds the visibility impairment attributable only to anthropogenic sources only within Oklahoma.

DEQ did not engage in "zero-out modeling" to make this determination. The comparison between the contribution of all anthropogenic sources in Oklahoma to visibility impairment at the Wichita Mountains and the difference between the uniform rate of progress and the reasonable progress goal comes instead from particulate source apportionment modeling. The particulate source apportionment modeling assumes that upwind states will not require controls that they do consider unreasonable.

In establishing the reasonable progress goal at the Wichita Mountains under 40 CFR § 51.308(d)(1)(i)(B), DEQ considered the emission reduction measures needed to achieve the uniform rate of improvement in visibility before 2018. In this statement, DEQ considered only emissions sources under its territorial jurisdiction. Removal of all sources in Oklahoma likely would fail to meet the uniform rate of progress.

For the reasons described in the implementation plan revision, DEQ does not consider the uniform rate of progress at the Wichita Mountains as an achievable goal. DEQ recognizes that reductions in emissions in Texas and in other upwind states and foreign countries might lead to reductions in visibility impairment beyond the reasonable progress goal. Reductions in emissions to attain the ambient air quality standard for ozone (O_3) may contribute to these reductions; however, DEQ cannot anticipate the ancillary benefit of these emissions reductions on visibility impairment at the Wichita Mountains, especially without knowing specifically which emissions reductions those authorities will implement.

20. **COMMENT:** Region 6 was unable to locate ODEQ's response to the requirements contained in Sections 51.308(d)(1)(vi) and 51.308(d)(3)(v)(G).

RESPONSE: The first regulation, 40 CFR § 51.308(d)(1)(vi), forbids DEQ from adopting a reasonable progress goal at the Wichita Mountains that represents less visibility improvement than that which DEQ expects to result from implementation of other requirements of the federal Clean Air Act before 2018. CENRAP and DEQ worked together to predict the results of implementation of BART and of other requirements of the Clean Air Act and used these predictions to estimate an emissions inventory for 2018. Chapter VII lists several important measures under the federal Clean Air Act, and Chapter VIII discusses the process of estimating emissions inventory for 2018 and the modeling of regional haze under these emissions inventories. DEQ expects the implementation of various requirements of the federal Clean Air Act (and regulations promulgated thereunder) to result in the improvement in visibility that this modeling indicates. DEQ acknowledges that various interpretations of and regulations under the federal Clean Air Act may result in lower emissions than those which CENRAP and DEQ estimated for 2018. DEQ also recognizes that social and cultural trends, especially considering the continued rapid population growth in the sovereign state of Texas, may result in countervailing increases in emissions not anticipated in CENRAP modeling. DEQ nevertheless considers the CENRAP modeling to inform a "best guess" of the emissions in 2018 under all provisions of the federal Clean Air Act and set its reasonable progress goal accordingly. The requirements of 40 CFR 51.308(d)(3)(v)(G) are addressed in Chapter VIII. This regulation requires DEQ to consider the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions before 2018 in developing its long-term strategy. The long-term strategy ideally would diminish point, area, and mobile source emissions before 2018. As adopted hereunder, the long-term strategy of DEQ at least constrains point-source emissions. DEQ included this assessment in Chapter VIII, but iterations in modeling in conjunction with CENRAP allowed for the use of results from preliminary simulations of future emissions in formulating the long-term strategy in Chapter VII and reasonable progress goals in Chapter IX.

21. **COMMENT:** Section 51.308(f) requires that ODEQ revise and submit its regional haze implementation plan revision to EPA by July 31, 2018 and every ten years thereafter. In response to this, ODEQ states on page 111, "DEQ awaits approval of this implementation plan before submitting any such revisions." ODEQ should clarify that it will comply with this requirement.

RESPONSE: DEQ understands that next SIP revision is to be submitted to EPA by 31 July 2018 and has the deleted the sentence.

22. **COMMENT:** Section 51.308(d)(4)(v) requires that ODEQ submit an emissions inventory that must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. The ODEQ has supplied an inventory for the baseline year, and for 2018. EPA understands that the ODEQ has emission inventory data available for 2005 and requests that it be included in the SIP. The preamble to the 1999 Regional Haze Rule (64 FR 35745) clarifies EPA authority for requiring the emission inventory of the "most recent year for which data are available," under 51.308(d)(4)(v):

> "Requirements Under Section 110(a)(2) of the CAA. Visibility SIP submittals must document certain program infrastructure capabilities consistent with the requirements of section 169B(e)(2) and section 110(a)(2) of the CAA. Section 169(B)(e)(2) requires States to revise their section 110 SIPs to ''contain such emission limits, schedules of compliance, and other measures as may be necessary'' to carry out regulations promulgated pursuant to this section. The EPA believes that this language authorizes EPA to ensure that States review their existing program infrastructures to ensure that the types of elements required by section 110(a)(2) for programs addressing the NAAQS are also sufficient for adoption and implementation of SIP measures for regional haze. The final rule does not include specific provisions addressing all elements of section 110(a)(2). However, section 51.308(d)(4)(iv) of the final rule requires the State to maintain and update periodically a statewide inventory of emissions of pollutants that contribute to visibility impairment. Where a State is also revising its SIP to incorporate changes to address the PM2.5 NAAQS, many of these revisions may be sufficient to address both PM2.5 and regional haze. The EPA encourages States to consider the needs of both programs when updating the provisions required by section 110 of the CAA to minimize any administrative burdens."

EPA requests that the ODEQ contrast its 2005 emission inventory with that from its baseline year of 2002, and 2018, in order to serve as a check of the EI projection methodology.

RESPONSE: It is correct that 2005 emissions inventory is the most recent complete inventory. This inventory is available to the public via EPA's website athttp://www.epa.gov/ttn/chief/eiinformation.html. A statement to that effect has been added to the Emission Inventory Chapter. DEQ is not aware that an analysis of this inventory is required, and there is insufficient time to accomplish this while meeting the deadline for submitting this SIP revision.

23. **COMMENT:** In the modeling section, it would be helpful to note where the modeling files (RH and BART) can be accessed. Inclusion of a printout (or screenshots) of the list of documents available on the CENRAP and ODEQ websites and/or ftp sites that are being relied upon in the SIP would make a good attachment to the SIP narrative.

RESPONSE: DEQ concurs that these additions could in some ways improve the content of this SIP; however, due in part to time restraints, DEQ has decided not to make the suggested changes.

DEQ received numerous written and oral comments from the public concerning the implementation of BART and the BART determinations included in the draft Regional Haze SIP revision. After considering the comments received, applicable portions of the Regional Haze SIP and/or attached BART determination(s) relevant to those comment(s) has been modified or removed. Consequently, except where a specific response was needed, the following comments have been addressed and/or are no longer applicable. The written submittals are included in Appendix 10-1.

OG&E – Mr. Kimber Shoops provided a written statement to duplicate his oral comments. In addition, OG&E provided many written comments which are included in a separate appendix.

Devon Energy submitted a letter December 16, 2009, signed by William F. Whitsitt, Executive Vice President of Public Affairs

Sierra Club, Oklahoma Chapter submitted a paper dated December 13, 2009, received by DEQ on December 16, 2009, signed by Bud Scott, Government Affairs Director

Chesapeake Energy Corporation submitted a paper dated December 16, 2009, received by DEQ on same day, which duplicates oral comments presented by Mr. Don Shandy.

Public Service Company of Oklahoma (PSO) submitted a letter dated December 16, 2009, received by DEQ on same day, signed by Howard L. Ground, Manager of Government Affairs.

24. **COMMENT:** Table VIII-2 projects an annual TPY increase of 32.86% in the state's Ammonia emissions inventory from the 2002 year. As previously stated, AEP/PSO requests the ODEQ to consider the complementary role of Ammonia in visibility impairing particulate formation. AEP/PSO sees the need for the ODEQ to address Ammonia control (in the near term) as also to cap Ammonia emission for meaningful visibility reduction in the near term and into the future.

RESPONSE: Public Service Company of Oklahoma correctly interprets a cell in the referenced table in the implementation plan revision. This statistic derives from projected inventories used in CENRAP modeling. DEQ will reevaluate ammonia emissions in preparation for any comprehensive periodic revision under 40 CFR 51.308(f).

DEQ considered the complementary role of ammonia in forming visibility-impairing particulate in assessing the particulate observations and in developing an emissions inventory. Following the leadership of EPA, DEQ does not consider regulation or reduction of ammonia emissions as a strategy to reduce particulate matter concentrations in this implementation plan revision. DEQ nevertheless requires permitted point sources, excluding animals in agricultural production, to report ammonia emissions.

DEQ currently does not regulate agricultural sources and consequently does not control most ammonia sources.

Western Farmers' Electric Cooperative – In a letter received by DEQ on December 16, 2009, signed by Gerald Butcher.

25. **COMMENT:** The DEQ has determined the impact of out-of-state emissions (primarily from the State of Texas) on visibility in the WIMO are significant. Conversely, Texas recently submitted its Regional Haze SIP Revision to EPA and therein indicated emissions originating from Texas do not impact visibility in the WIMO. Therefore, there appears to be a significant disagreement between the findings from each State. How does the DEQ propose to resolve this issue?

    RESPONSE: DEQ stands by its assessment that Texas emissions significantly impair visibility at the Wichita Mountains. EPA can evaluate both SIPs and will be ultimately responsible for determining which findings are supported by the technical demonstrations included in each SIP.

26. **COMMENT:** Did the DEQ advise Texas that additional emission reductions from Texas sources would not be needed to help Oklahoma meet the WIMO reasonable progress goals, and if so, on what basis was such determination made?

    RESPONSE: DEQ advised Texas of its finding during the consultation process that Oklahoma would be unable to meet the uniform rate of progress without additional reductions, including those from Texas sources. However, DEQ does not have the regulatory authority require emissions reductions in other states. Only Texas and EPA can require those reductions.

27. **COMMENT:** … Based on the above and the fact that "… even the elimination of all anthropogenic sources within Oklahoma is not sufficient to comply with uniform rate of progress", the DEQ concluded "any effective strategy for managing visibility impairment at the Wichita Mountains must address outside sources including regional and international transport." However, the Revision is silent as to how such outside sources will be addressed.

    RESPONSE: See response to previous comment.

Oral Comments Received at the December 16, 2009 Public Hearing

Joe Kordzi (EPA, Region 6)

COMMENT: I would like to urge the Air Quality Council and Environmental Quality Board to adopt the Oklahoma Regional Haze Plan. It is the opinion of EPA Region 6 that the measures contained within Oklahoma's regional haze plan will do much to improve visibility at the Wichita Mountains, with co-benefits to DEQ's other air quality programs. Furthermore, it is vitally important this plan be submitted to us for review as soon as possible. EPA Region 6 has submitted written comments of the plan that we request be entered into the record.

Paul Renfrow (OGE Energy Corp)

COMMENT: We disagree with and oppose the draft proposal for several reasons: First and most importantly, the proposal will result in the largest single rate increase for our customers in the company's 108 year history. This cannot be minimized nor is it contrived. The proposal forces us to spend more than ONE Billion DOLLARS of customer's money to add pollution control devices, commonly called scrubbers, to our coal plants. Those coal plants are each between 25-30 years old and somewhere in the last half of their planned useful lives. This proposal will actually PROLONG the life of the coal plants when it seems everyone in the country wants utilities to quit using coal. This proposal is completely contrary to the national efforts to reduce CO2 emissions. While the Regional Haze rule has the desirable intention of making our wilderness areas more beautiful over the next 50 years, this is, frankly, an inefficient, contradictory compliance exercise that ignores innovative or creative approaches. We strongly recommend that the OG&E alternative plan be adopted **b**y the DEQ and included in their final State Implementation plan to be filed with the EPA.

Kimber Shoop (OG & E)

COMMENT: OG&E believes that anyway you look at it, scrubbers are not cost effective. : That is why we developed our alternative proposal. OG&E strongly urges the State of Oklahoma to instead consider the alternative proposal submitted by OG&E on September 23, 2009 to achieve compliance with regional haze targets for these four units. OG&E's alternative proposal will ultimately achieve the same visibility improvement as set forth in the Revised SIP, but in a cost effective manner through the use of more natural gas-fired and wind generation to meet the electric needs of our customers.

Don Shandy (Chesapeake Energy Corporation)

COMMENT: Rather than requiring huge capital investment to the Oklahoma coal-fired units that are more than 30 years old, such units should either convert to natural gas firing systems or be replaced with new natural gas fired generation units. Oklahoma must begin to effectively address emissions from coal-fired electric generation plants in Texas. … And these sources need to be evaluated with the same level of scrutiny that sources inside Oklahoma are being evaluated. While the Plan acknowledges impact from out-of-state sources and to some extent, attempts to address this matter via consultation with Texas, and if we attempt to address this in consultation with Texas and we have an agreement, according to the document, to allow Oklahoma the opportunity to comment on pending Texas air permits - permit application for sources within 300 kilometers of our border, we believe this approach is inadequate. This is particularly the case given DEQ is requiring again or mentioning excessive and expensive sulfur emission control on coal-fired electric generation units located inside the state of Oklahoma. Chesapeake's comment is that in light of overwhelming evidence that Texas sources impact visibility at the Wichita Mountains, and given the potentially large financial impact on Oklahoma electric generation facilities and rate payers, DEQ should have requested additional reduction from Texas sources to meet the reasonable progress goal. While Chesapeake acknowledges that scrubber technology would result in significant reductions of sulfur emissions, which will accomplish – such will be accomplished only again after an extraordinary and unwarranted investment by rate payers in this state. …And it would represent one of the largest capital investments in Oklahoma history. While we definitely agree that we've got to make movement to protect the Class I area, there has to be a very hard look at these numbers. Chesapeake believes that the expenditure of funds for this type of emission control equipment is imprudent. While it would undoubtedly be acceptable to DEQ, the culpable coal-fired generation sources should focus on the development and utilization of more environmentally friendly electric generation units and fuels.

Bud Scott (Sierra Club)

COMMENT: I have submitted formal comments as well that should be entered into the record. One of our major issues with the draft SIP today first lies with the exclusion for most of the analysis of the Class I areas that are impacted outside of the state of Oklahoma, primarily Caney Creek and the Upper Buffalo Area. Those two we would request be given the same level of analysis as the Wichita Mountain Wilderness Refuge. The second of addressing out-of-state issues primarily with the state of Texas. Those have already been addressed by parties at Chesapeake and Oklahoma Gas and Electric. That's one of our most important points is that we could be given alternative approaches which were very little addressed through the SIP for dealing with the out-of-state issues on transport, the out-of-state issues with direct emissions, and its impact on the Wichita Mountain Wilderness Area. Number two, we've identified in the alternative approaches for implementation of the BART and BACT that in the alternative approaches we look more towards fuel switching provisions which were not adequately addressed in the provided SIP. Most of the SIP addressed the direct implementation of BART and then somewhat in BACT. And we would just like to see more of that approached and given a little more detail. And then finally, we would really just like to see more cooperation on the interstate level. So ultimately the sierra Club while we do generally support the implementation of the Best Available Retrofit Technologies and Best Available Control Technologies at the same time we feel like the plan here in Oklahoma could be revised to address some of the alternatives available that will be best for the rate payers in Oklahoma, the citizens of Oklahoma, and for our natural resources.

Darryl Smeete (Devon Energy)

COMMENT: We're here to support OG&E's application for an alternative proposal to the Regional Haze Plan. In short what OG&E is saying is that it not only is more economical but we have less greenhouse gas emissions by converting some of the base load generating capacity go gas fueled rather than coal fueled. We think the proposal by OG&E is a win-win. First of all it reduces emissions. Second of all it puts people to work, drilling and completing wells. Once those wells are on stream and produces gas and that gas with subsequent productions tax. That tax goes to the State of Oklahoma and to the other states where it is produced.