OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **August 1, 2012**

TO: Phillip Fielder, P.E., Permits and Engineering Group Manager

THROUGH: Kendal Stegmann, Sr. Environmental Manager, Compliance and Enforcement

THROUGH: Phil Martin, P.E., Existing Source Permits Section Manager

THROUGH: Peer Review, Richard Kienlen

FROM: Herb Neumann, Regional Office at Tulsa (ROAT)

SUBJECT: Evaluation of Permit Application No. **2009-179-C (M-2) PSD**
Grand River Dam Authority (GRDA)
Chouteau Coal-Fired Complex (CFC) Units 1 and 2
Sections 20, 21, 28 & 29, T20N, R19E, Mayes County, OK
Directions: 3 miles E. of Chouteau on Hwy 412, one mile N. on Hwy 412B
Driveway entrance at 36.19332°N, 95.28475°W

SECTION I INTRODUCTION

GRDA generates electricity using steam turbines (SIC 4911). The facility is currently operating under Part 70 Operating Permit No. 2009-179-TVR2 (M-1), issued November 30, 2011. The facility now applies for a construction permit to add low-NO_X burners (LNB) and overfire air (OFA) to Units 1 and 2 to reduce emissions of NO_X.

SECTION II FACILITY DESCRIPTION

The CFC generating facility consists of two coal-fired, Foster Wheeler opposed wall boilers, designated as Units 1 and 2. Unit 1, which has a rated capacity of 490 MW, was built in 1978 and is designed to burn sub-bituminous (Wyoming) coal. Current air quality control equipment on Unit 1 consists of an electrostatic precipitator (ESP). Unit 2, which has a rated capacity of 520 MW, was built in 1982 and is designed to burn sub-bituminous (Wyoming) coal, or a blend of Wyoming and Oklahoma bituminous coal. An alternative operating scenario for Units 1 and 2 authorized by Permit No. 2009-179-TVR2 (M-1) consists of operating on refined coal, using additives S-Sorb and Mer-Sorb in a process known as Chem-Mod. Existing flue gas desulfurization (FGD) air quality control equipment on Unit 2 consists of a spray dryer absorber (SDA) followed by an electrostatic precipitator (ESP). The igniters in these units are gas-fired. Two auxiliary oil-fired boilers were originally installed for start-up of the main units, but are no longer needed for this purpose. They are operated occasionally to assure that they are still in good condition. They may be used for supplying steam to plant auxiliary equipment and for plant heating as necessary. These auxiliary boilers use propane as an igniter fuel.

Coal fuel is delivered to the site via rail and truck. Wyoming coal is received by rail in unit trains that are unloaded using a rotary car dumper. The rotary dumper empties each car by turning it upside down. Wyoming coal is then processed through a series of material handling systems designed to stack out, reclaim, crush, and convey the fuel to the boilers. "Reclaim" means to take coal from a pile and send it to the boiler. Reclaimed coal is temporarily stored in bins above the boilers until it is actually fed into the boilers. Oklahoma coal is received by trucks and manually stockpiled. Oklahoma coal is then processed through a series of material handling systems designed to reclaim, crush, and convey the fuel to the boiler. The alternative operating scenario is quite similar to the process described here, with minor modifications of equipment to allow for the blending of the two additives into the coal stream. A more detailed description may be found in the memorandum associated with the current operating permit.

FGD on Unit 2 uses lime. The product is received in trucks, stored in silos, and there is no crushing or grinding of the material before use. An onsite landfill receives scrubber waste, as well as any fly ash and bottom ash that is not otherwise sold for approved beneficial reuse.

SECTION III. PROJECT DESCRIPTION

GRDA proposes the installation of LNB/OFA technology on Units 1 and 2 to reduce NO_X emissions from the CFC. LNB and OFA are two forms of combustion control that have been combined in a single technology to reduce NO_X emissions from pulverized coal fired units. NO_X, primarily in the form of NO and NO_2, is formed during combustion by two primary mechanisms; thermal NO_X and fuel NO_X. Thermal NO_X results from the dissociation and oxidation of nitrogen in the combustion air. The rate and degree of thermal NO_X formation is dependent upon oxygen availability during the combustion process and is exponentially dependent upon the combustion temperature. Fuel NO_X, on the other hand, results from the oxidation of nitrogen organically bound in the fuel. Fuel NO_X is the dominant NO_X producing mechanism in the combustion of pulverized coal and typically accounts for 75 to 80 percent of total NO_X.

All LNBs offered commercially for application to coal fired boilers control the formation of NO_X through some form of staged combustion. The basic NO_X reduction principles for LNBs are to control and balance the fuel and airflow to each burner, and to control the amount and position of secondary air in the burner zone so that fuel devolatilization and high temperature zones are not oxygen rich. In this process, the mixing of the fuel and the air by the burner is controlled in such a way that ignition and initial combustion of the coal takes place under oxygen-deficient conditions, while the mixing of a portion of the combustion air is delayed along the length of the flame. The objective of this process is to drive the fuel-bound nitrogen out of the coal as quickly as possible, under conditions where no oxygen is present, and where it will be forced to form molecular nitrogen rather than be oxidized to NO_X.

OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect of the LNBs and further reducing NO_X emissions. Residual unburned material, such as CO and unburned carbon that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

The net result of the staged combustion associated with an LNB is usually lower peak combustion temperatures and longer and/or wider flames, due to the delayed mixing process. The lower combustion temperatures and potential for encroachment on cooled boiler surfaces are the main reasons that low-NO_X combustion techniques may be associated with the potential for increased carbon in ash and higher CO emissions. The resulting efficiency loss due to this potential can be somewhat offset, however, by the lower total excess air demand that is part of the low-NO_X firing strategy. Additionally, improved stoichiometric control (air and coal flow monitoring) at the burners will improve combustion by ensuring a better coal/air balance across all of the coal burners, and maintaining coal fineness will allow for good coal burnout.

GRDA's project contractor has guaranteed emission test results of 0.17 lb/MMBTU for both NO_X and CO for each Unit. The CO rate is based on a guarantee of 200 ppmv of CO at 3% O_2 in the stack exhaust.

SECTION IV. EQUIPMENT

All EUGs are listed, but the only EUGs for which emissions points are listed are those directly related to the current project. Stack parameters and information about existing control devices are not shown in this listing, either. More detail may be found in operating permit 2009-179-TVR2 (M-1).

EUG 1 Entire Facility

This EUG is established to cover all rules or regulations that apply to the facility as a whole.

EUG 2 Combustion Sources - Unit 1

EU	Point	Make/National ID#	MW	MMBTU/hr	Const Date
B-02	1	Foster-Wheeler #6844	490	5131	3/1/78

EUG 3 Combustion Sources - Unit 2

EU	Point	Make/National ID#	MW	MMBTU/hr	Const Date
B-02	2	Foster-Wheeler #6905	520	5296	3/24/82

EUG 4 Combustion Sources - Auxiliary Boilers

EUG 5 Coal Transfer, Conveying, Crushing

EUG 6 Lime and Ash Handling

EUG 7 Truck & Maintenance Vehicle Traffic and Material Storage

Insignificant Sources

SECTION V. EMISSIONS

The approach taken for this construction permit is different from that used in the analysis for the most recent Part 70 renewal operating permit. Emission estimates for the Part 70 permit reflect continuous operations, using emission factors from numerous sources, including stack tests, AP-42, and previously-issued permits. The intent of that approach is to maximize results in order to provide a conservatively high calculation of potential to emit (PTE). In the present instance, the analysis requires an accurate accounting of actual emissions in order to construct a baseline case against which emissions from the proposed project may be compared. Because information for EUGs 4, 5, 6, and 7 is not necessary for the PSD analysis, only operating permit memorandum (PTE) totals for each are shown.

Data for EUGs 2 and 3 are based on current factors used in the annual emission inventory (AEI or "turn-around document") and from the Clean Air Markets database, an EPA summary of acid rain reporting by the facility. Oxides of nitrogen and of sulfur (NO_X and SO_2) are CEMs data. Carbon monoxide uses emission factors from Table 1.4-1 of AP-42 (7/98) for natural gas and from Table 1.1-3 of AP-42 (9/98) for coal at Unit 1. The CO factor for coal at Unit 2 is taken from a stack test on 8/12-14/1986. VOC factors are taken from AP-42 (9/98) Table 1.1-19 for pulverized coal, wall-fired, dry bottom furnace utility boiler (coal) and from AP-42 (7/98) Table 1.4-2 (natural gas), and factors for lead are from AP-42 (9/98) Table 1.1-18 for coal and from AP-42 (7/98) Table 1.4-2 for natural gas. Sulfuric acid mist calculations assume stoichiometric conversion of 1% of SO_2 to H_2SO_4. The PM emission factors for coal operation are taken from stack tests for Unit 1 on 12/2-3/1981 and for Unit 2 on 8/12-14/1986. The PM_{10} fraction of all PM was taken from the Profile for Coal-Fired Power Plant with ESP found in the EPA Air Emissions Species Manual, Volume II, Particulate Matter Species Profiles, 2nd Edition (EPA 450/2-90-001b, 1/90). The $PM_{2.5}$ fraction of all PM was taken from Table 1.1.-6 of AP-42 (9/98). Emission factors for PM emissions for natural gas operations are taken from Table 1.4-2 of AP-42 (7/98). Fluorides are calculated by correcting emissions of hydrogen fluoride (HF) using the weight ratio of HF to fluorine. HF emissions from both units are based on stack test results. More details for all factors are listed in the current renewal operating permit.

Emissions of greenhouse gasses (GHGs) are based on the following assumptions and calculations. Annual emissions of CO_2 are the summation of monthly emissions obtained from the Clean Air Markets database. Methane emissions are based on a pulverized coal, wall-fired, dry bottom furnace utility boiler emission factor of 0.04 lb/ton of coal, taken from Table 1-19 of AP-42 (9/98), and a factor of 2.3 lb/MMCF for gas, taken from Table 1.4-2 of AP-42 (7/98). Nitrous oxide emissions are based on a pulverized coal, wall-fired, dry bottom furnace utility boiler emission factor of 0.03 lb/ton of coal, taken from Table 1.1-19 of AP-42 (9/98), and a factor of 2.2 lb/MMCF for gas, taken from Table 1.4-2 of AP-42 (7/98). CO_2 equivalents (CO_2e) are based on the global warming potential for applicable pollutant as listed in Table A-1 of 40 CFR Part 98.

Regardless of analyses that typically reflect federal standards for PM, the facility is not exempt from compliance with State of Oklahoma standards that require total PM, otherwise described as filterable and condensable or front-half and back-half.

The facility used all of the information described in the second paragraph of this Section V to construct a monthly table of emissions for the five year period 2007-2011, along with 24-month running cumulatives for each pollutant. Because the baseline actual emissions requirement for PSD analysis for each pollutant is based on any consecutive 24-month period in the last five years, the table for EUGs 2 and 3 shows the ending date for the 24-month period selected for each pollutant. Note that although this table does present a maximum for each pollutant, data are not required to be contemporaneous for any two pollutants.

Pollutant	TPY	Ending date
CO	1,120	January 2009
NO_X	14,552	November 2011
PM	1,110	January 2009
PM_{10}	743	January 2009
$PM_{2.5}$	322	January 2009
SO_2	18,339	February 2010
VOC	137	February 2009
Lead	0.96	February 2009
H_2SO_4	280	November 2009
Fluorides	6.01	February 2009
TRS (including H_2S)	---	---
GHG (mass)	8,537,460	December 2011
GHG (CO_2e)	8,560,438	December 2011

Emissions From Other Combustion Sources (EUG 4)

Emission totals are shown, but details are not necessary for the current project.

Pollutant	Lb/hr	TPY
PM/PM_{10}	11.6	3.07
VOC	5.61	1.69
CO	88.2	26.0
SO_2	9.64	2.00
NOx	123	34.5

Particulate Emissions From Coal Handling (EUG 5)

Emission totals are shown, but details are not necessary for the current project.

Pollutant	Lb/hr	TPY
TSP totals	94.8	113
PM_{10} totals	44.8	53.3
$PM_{2.5}$ totals	6.79	8.07

Particulate Emissions From Lime and Ash Handling (EUG 6)

Emission totals are shown, but details are not necessary for the current project.

Pollutant	Lb/hr	TPY
TSP totals	3.12	0.44

PM_{10} totals	1.48	0.21
$PM_{2.5}$ totals	0.22	0.03

Particulate Emissions From Unpaved Road Vehicle Traffic (EUG 7)

Emission totals are shown, but details are not necessary for the current project.

Pollutant	TPY
PM_{10} totals	8.69
$PM_{2.5}$ totals	0.87

Particulate Emissions From Paved Road Vehicle Traffic (EUG 7)

Emission totals are shown, but details are not necessary for the current project.

Pollutant	TPY
PM_{10} totals	2.70
$PM_{2.5}$ totals	0.27

Particulate Emissions From Storage Pile Wind Erosion (EUG 7)

Emission totals are shown, but details are not necessary for the current project.

EU ID#	Emissions, TPY
TO-03-006	41.0
TO-03-007	57.4
TO-03-008	57.4

Speciated and Trace Compound Emissions

Numerous volatile and metallic compounds and elements were addressed in the operating permit. Because there is no expected increase in fuel use and because these numbers are generally small, there is no need to repeat the earlier analysis here. Lead and fluorides, each with estimated emissions of some interest in the operating permit, are considered in this memorandum in the discussion that covers criteria pollutants.

SECTION VI. INSIGNIFICANT ACTIVITIES

The current project neither adds nor subtracts from the insignificant activities identified in the Part 70 operating permit.

SECTION VII. PSD REVIEW

This is a construction project that is expected to cause an increase in CO emissions. The first step in reviewing the possible applicability of PSD requirements is to determine if a projected emission increase (PEI) will occur. The method used to calculate the PEI for this application is commonly called the "actual-to-projected actual" applicability test. It compares projected actual emissions to baseline actual emissions. Baseline actual emissions were presented in the EUGs 2 and 3 discussion in Section V (Emissions) earlier. According to OAC 252:100-8-31, the projection period begins on the date the affected facility resumes regular operation and includes the subsequent first ten years of operation if the project involves increasing the unit's design capacity or its potential to emit that regulated NSR pollutant, and full utilization of the unit would result in a significant emissions increase, or a significant net emissions increase at the major stationary source. This is true for the units' CO PTE, so a 10 year projection period is utilized.

To calculate the Projected Actual Emissions (PAE), it is necessary to account for the emissions associated with the future business activity level (i.e., electrical demand growth) over the course of the projection period and with any projected emissions change associated with the proposed Project itself.

First, to determine the projected increase associated with future business activity, GRDA commissioned a dispatch and forecast load study. In the study, it was assumed that the CFC units will be dispatched to serve load (electric demand), meet spinning reserve requirements (specific minimum capacity available for quick transmissions), and make spot sales (short-term demand outside normal customer base), if available. Additionally, both planned and unplanned unit outages were factored into the load projection forecast. Capacity factor is a measure of actual demand or use compared with potential capacity. The capacity factor forecasts peak annual load demands of 84.8 and 89.2 percent capacity factor for Units 1 and 2, respectively, over the 10-year projection period. Compared with the historical maximum annual capacity factors over the baseline period (2005-2009) of 78.7 and 83.1 for Units 1 and 2, respectively, the load projection forecast represents a 6.1 percent capacity factor increase for both units after the baseline period.

Secondly, as previously discussed, the Project itself will result in a decrease in NO_X emissions and an increase in CO emissions. Therefore, the PAE for the projection period is calculated using the expected new NO_X and CO emission factors associated with the LNB/OFA systems, along with the forecasted load growth of 6.1 percent that the CFC is capable of accommodating. The PAE for each pollutant, emission unit, and total for the Project are presented in the following table. Thus, the PAE is simply an estimate of the post-project actual annual emissions that CFC Units 1 and 2 are expected to have as the result of the LNB/OFA system installation and the natural capacity factor response of the CFC to anticipated load growth.

Summary of Projected Actual Emissions (PAE)

Pollutant	TPY		
	Unit 1	Unit 2	Project Total
CO	3,441	4,119	7,560
NO_X	3,353	3,890	7,242
PM	729	449	1,177
PM_{10}	488	300	789
$PM_{2.5}$	211	130	341
SO_2	14,503	4,954	19,457
VOCs	69	77	146
Lead	0.48	0.54	1.02
H_2SO_4	221	76	297
Fluorides	5.79	0.59	6.37
H_2S	Negligible	Negligible	Negligible
Total Reduced Sulfur	Negligible	Negligible	Negligible
GHGs (Mass)	3,992,724	5,065,522	9,058,245
GHGs (CO_2e)	4,003,974	5,078,651	9,082,624

Pollutant	TPY	Ending date
CO	1,120	January 2009
NO_X	14,552	November 2011
PM	1,110	January 2009
PM_{10}	743	January 2009
$PM_{2.5}$	322	January 2009
SO_2	18,339	February 2010
VOC	137	February 2009
Lead	0.96	February 2009
H_2SO_4	280	November 2009
Fluorides	6.01	February 2009
TRS (including H_2S)	---	---
GHG (mass)	8,537,460	December 2011
GHG (CO_2e)	8,560,438	December 2011

Emission increases that are not directly related to the proposed project or modification (such as future business activity in the form of electrical demand growth) may be excluded from the PEI formula. For the purpose of this application, these types of emission increases are referred to as excludable emissions (EE). The EE are those emissions that could have been accommodated during the baseline period by the pre-project (unmodified) unit, and that are also unrelated to the proposed modifications themselves. Using the same load forecast described above, the EE were calculated from the baseline emissions by increasing the BAE by 6.1 percent, as presented in the following table.

Summary of Excludable Emissions (EE)

Pollutant	TPY		
	Unit 1	Unit 2	Project Total
CO	579	609	1,188
NO_X	7,411	8,028	15,439
PM	729	449	1,177
PM_{10}	488	300	789
$PM_{2.5}$	211	130	341
SO_2	14,503	4,954	19,457
VOCs	69	77	146
Lead	0.48	0.54	1.02
H_2SO_4	221	76	297
Fluorides	5.79	0.59	6.37
H_2S	Negligible	Negligible	Negligible
Total Reduced Sulfur	Negligible	Negligible	Negligible
GHGs (Mass)	3,992,724	5,065,522	9,058,245
GHGs (CO_2e)	4,003,974	5,078,651	9,082,624

Finally, the PEI is calculated as the difference between the PAE and the greater of the BAE or the EE for each pollutant. Subtracting the EE emissions from the PAE emissions to determine the PEI ensures that the emission increase resulting from any future business activity is excluded from the emission increase formula, as allowed under the NSR/PSD rules. The PEI is then compared with the PSD significant emission rate (SER) to determine PSD applicability on a pollutant-by-pollutant basis. The following table shows the difference calculation and the comparison to the SER.

CALCULATION OF PEI AND DETERMINATION OF PSD REVIEW (TPY)

Pollutant	PAE	BAE	EE	PEI	SER	PSD Review?
CO	7,560	1,120	1,188	6,372	100	Yes
NO_X	7,542	14,552	15,439	-8,197	40	No
PM	1,177	1,110	1,177	0	25	No
PM_{10}	789	743	789	0	15	No
$PM_{2.5}$	341	322	341	0	10	No
SO_2	19,457	18,339	19,457	0	40	No
VOC	146	137	146	0	40	No
Lead	1.02	0.96	1.02	0	0.6	No
H_2SO_4	297	280	297	0	7	No
Fluorides	6.37	6.01	6.37	0	3	No
H_2S	Negligible	Negligible	Negligible	0	10	No
TRS	Negligible	Negligible	Negligible	0	10	No
GHGs (Mass)	9,058,245	8,537,460	9,058,245	0	0	No
GHGs (CO_2e)	9,082,624	8,560,438	9,082,624	0	75,000	No

As shown, the proposed project will increase emissions above the PSD significance level for carbon monoxide, which is subject to further review below. Full PSD review of emissions consists of the following. Although much of the PSD review is taken from the application verbatim, modifications have been made at various points. The review generally includes the following steps and the discussion will address each in order.

A. determination of best available control technology (BACT)
B. evaluation of existing air quality and determination of monitoring requirements
C. evaluation of PSD increment consumption
D. analysis of compliance with National Ambient Air Quality Standards (NAAQS)
E. ambient air monitoring
F. evaluation of source-related impacts on growth, soils, vegetation, visibility
G. evaluation of Class I area impact

A. BACT

As required under NSR/PSD regulations, the BACT analysis employed the USEPA's recommended top-down, five-step analysis process to determine the appropriate BACT emission limitations for the Project. The BACT analysis was conducted in the following manner.

Step 1: Identify All Control Technologies

The first step in a "top-down" analysis is to identify all available control options for the emission unit in question. These options consist of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. These potentially include lower emitting processes, practices, and post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques that are classified as pre-combustion controls. The category of post-combustion controls includes various add-on controls for the pollutant being controlled.

Oxidation Catalysts

The CO oxidation catalyst process utilizes a platinum/vanadium catalyst that oxidizes CO to CO_2. The chemical process is a straight catalytic oxidation/reduction reaction requiring no reagent. Catalytic oxidation emission reduction methods have been proven in the industry for use on natural gas and oil fueled combustion turbine sources, but not on coal fired boilers. The primary technical challenge faced with trying to install an oxidation catalyst on a coal fired boiler is that the catalyst needs to be located in a flue gas high temperature region, which would most likely be prior to the economizer. This location, along with the potential fouling effects of the flue gas, would render the catalyst ineffective, even on a short-term basis.

Good Combustion Controls

As products of incomplete combustion, CO emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boilers. Typically, the measures taken to minimize the formation of NO_X during combustion (such as the installation of LNB/OFA) tend to inhibit complete combustion, which increases the emissions of CO. On the other hand, high combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions, but tend to increase NO_X

formation. Therefore, in terms of combustion controls, the best control technology for CO directly conflicts with the LNB/OFA's ability to reduce NO_X. Nonetheless, LNB burner manufacturers strive for the delicate balance of decreasing NO_X emissions while at the same time limiting CO formation, resulting in good combustion control practices based on a boiler-specific and fuel-specific LNB/OFA burner design.

Step 2: Eliminate Technically Infeasible Options

The second step is to eliminate the technically infeasible control options from those identified in Step 1. A technically infeasible control option is one that has not been "demonstrated"; or more specifically, a technology that has not been installed and operated successfully on a similar type of unit of comparable size. A technology is considered "demonstrated" for a given unit based on its "availability" and "applicability." "Availability" is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. "Applicability" is defined as an available control option that can reasonably be installed and operated on the unit type under consideration.

The application of an oxidation catalyst to a coal fired boiler presents many substantial challenges that render this control technology not technically feasible for further consideration as a control alternative for CO. A review of the USEPA RACT/BACT/LAER Clearinghouse (RBLC) reveals that the database contains no record of add-on control equipment for the control of CO on a solid fuel boiler, and GRDA is not aware of this control technology's ever having been applied to a solid fuel boiler. Technical challenges that render an oxidation catalyst control technically infeasible for Units 1 and 2 include the following.

- The oxidation catalyst will not only oxidize CO, but will also oxidize a predominant portion of SO_2 to SO_3, forms corrosive and undesirable sulfuric acid vapor emissions in the presence of water. Additionally, if additional controls such as an SNCR/SCR were installed on Units 1 and 2, even more SO_2 would be oxidized to SO_3 and would likely result in the quick fouling of the air heater and equipment corrosion downstream.
- Acid gases and trace metals in the flue gas from the combustion of solid fuel will quickly poison the catalyst, making the control technology ineffective in its intended role.

While the CO oxidation catalyst is eliminated from further consideration for the reasons stated above, good combustion controls are well demonstrated and available, and thus considered technically feasible for the control of CO in this BACT analysis.

Step 3: Rank Remaining Control Technologies by Effectiveness

The third step is to rank all the remaining control alternatives not eliminated in Step 2 based on their control effectiveness for the pollutant under review. In this step, the feasible technologies are reviewed in order to determine the control effectiveness on either a percent removal basis or emission level, or both, based on an engineering analysis and document review of the technology applied to similar units. The following informational databases, clearinghouses, documents, and studies were used to identify recent control technology determinations for similar source categories and emission units.

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC).
- USEPA's National Coal Fired Utility Projects Spreadsheet (August 2009).
- Federal/State/Local new source review permits, permit applications, and associated inspection/test reports.
- Technical journals, newsletters, and reports.
- Information from air quality control (AQC) technology suppliers.
- AQC engineering design studies for this and similar units.

A search of the information contained in the USEPA RACT/BACT/LAER Clearinghouse (RBLC) was conducted to determine the top level of CO control for new and LNB/OFA retrofit coal boilers. A search was also conducted for recently permitted new and LNB/OFA retrofit coal fired facilities whose BACT determinations have not yet been included in the current database. The results are documented in Attachment A of the BACT discussion in the application. The list contains 125 items and is not reproduced here. It indicates that good combustion controls (GCC) is the top control for CO emissions from coal fired boilers. In fact, GCC is the only control identified for similar sources to reduce CO emissions.

The data exhibit a very large range of CO BACT emission limit determinations by various permitting authorities across the country for new coal-fired boilers and LNB/OFA retrofits, with determinations ranging from 0.015 lb/MMBtu for newly proposed coal fired boilers to as high as 1.26 lb/MMBtu for an OFA retrofit. The more than an order of magnitude range in CO BACT determinations are reflective of the high variability of this pollutant's formation and indicative of the boiler-specific design and fuel conditions that must be taken into consideration when determining a CO BACT emission limit. Using only those retrofit boilers for which the limit is set on a 30-day average, the accepted standards average 0.268 lb/MMBTU. Forming the same average for new boilers that have 30-day averaging yields 0.144 lb/MMBTU.

As previously mentioned, the lowest CO BACT emission limit determinations are for newly proposed boilers, while the higher CO BACT emission limit determinations are generally associated with LNB/OFA retrofit projects such as that proposed for GRDA's CFC. The reason for this variability is that LNB/OFA retrofits are installed on existing coal fired boilers for the sole purpose of reducing NO_X emissions; and as such, cannot be optimized as effectively for CO reduction as they can for a new unit because of the fixed design characteristics of the existing boiler. CO emissions, as a product of incomplete combustion, are by their nature a function of the specific boiler type and the fuel characteristics, which is reflected in the emissions guarantees that vendors are willing to make for a LNB/OFA retrofit project.

Therefore, when determining CO BACT emission limits for CFC Units 1 and 2, it is appropriate to focus the review and analysis of previous determinations on those existing units that have recently undergone similar LNB/OFA retrofit installations and permit actions. The following 27 determinations were extracted from the previously mentioned list to illustrate determinations recently made by permitting authorities for retrofit projects similar to that proposed for GRDA's CFC Units 1 and 2.

CO Requirement	Averaging period	Facility/Unit Name	State	Date
0.17 lb/MMBtu	30-day rolling	KCK's Nearman Creek Power Sta (#1)	KS	4/11
0.42 lb/MMBtu	30-day rolling	KCK's Quindaro Power Sta (#2)	KS	4/11
0.34 lb/MMBtu	unknown	SWEPCO'sTolk Sta Power Plant	TX	3/11
0.30 lb/MMBtu	24-hour	Consumers Energy's Tes Filer City Plt	MI	6/10
0.15 lb/MMBtu	30-day rolling	Minnesota Power Div Allete Boswell	MN	4/10
0.33 lb/MMBtu	unknown	NRG's Limestone Plant	TX	2/10
0.33 lb/MMBtu	30-day rolling	SouthWest PSO's Harrington Sta #1	TX	1/10
0.149 lb/MMBtu	unknown	Mississippi Power Co Jack Watson	MS	9/09
0.02 lb/MMBtu	unknown	Pacificorp's Naughton #3	WY	5/09
0.25 lb/MMBtu	30-day rolling	Pacificorp's Wyodak Plant (Unit 1)	WY	5/09
0.25 lb/MMBtu	30-day rolling	Pacificorp's Naughton Plant (Units 1 and 2)	WY	5/09
0.50 lb/MMBtu	30-day rolling	Omaha Public Power District's (OPPD) Nebraska City Station	NE	2/09
0.50 lb/MMBtu	30-day rolling	Salt River Project's Coronado Generating Station (Units 1 and 2)	AZ	1/09
0.25, 0.20 lb/MMBtu	30-day rolling	Pacificorp's Dave Johnston Plant (Units 3 and 4, respectively)	WY	6/08
0.18, 0.15 lb/MMBtu	30-day rolling	Orlando Utilities Commission's Stanton Energy Center (Units 1 and 2)	FL	2/08
0.25 ln/MMBTU	30-day rolling	Westar Energy's Tecumseh Energy Ctr	KS	11/07/
0.17 lb/MMBtu	30-day rolling	Progress Energy's Crystal River Plant (Units 4 and 5)	FL	5/07
0.20 lb/MMBtu	30-day rolling	Tampa Electric Company's Big Bend Station (Unit 4)	FL	5/07
0.163 lb/MMBtu	30-day rolling	Iowa Power and Light's (IPL) Ottumwa Generating Station	IA	2/07
0.35 lb/MMBtu	30-day rolling	City Utilities of Springfield's James River Power Station (Units 3, 4, and 5)	MO	12/06
0.20 lb/MMBtu	30-day rolling	Lakeland Electric's McIntosh Plant	FL	12/06
0.20 lb/MMBtu	30-day rolling	Cleco Corp's Dolet Hills Power Station	LA	11/06
0.15 lb/MMBtu	8-hour rolling	Platte River Power Authority's Rawhide Energy Station	CO	9/06
0.50 lb/MMBtu	30-day rolling	Nebraska Public Power District's Gerald Gentleman Station (Unit 1)	NE	8/06
1.26 lb/MMBtu	3-hour	MidAmerica Energy's George Neal North Plant (Unit 1)	IA	12/05
0.25 lb/MMBTU	30-day rolling	Westar Energy's Jeffrey Energy Ctr	KS	10/05
0.42 lb/MMBtu	calendar day	MidAmerica Energy's Neal Energy Center South	IA	9/05

These determinations, spanning the last six-plus years, range from 0.2 to 1.26 lb/MMBtu, with an average CO BACT emission rate of approximately 0.33 lb/MMBtu. All but eight of the CO

BACT determinations specified above require a 30-day rolling average as a basis for compliance. The top, and only control technology determination listed, is the use of GCC for the reduction of CO emissions from coal fired boilers.

Step 4: Evaluate Most Effective Controls and Document Results
Additional evaluations are performed to consider and compare the energy, environmental, and economic impacts associated with implementing the viable control alternatives.

The energy impact evaluation considers the energy penalty or benefit resulting from the operation of the control technology at the facility. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which ultimately affects the cost-effectiveness of the control technology. There are no significant energy impacts that would preclude the use of GCC to limit the emissions of CO.

The environmental impact evaluation considers the collateral environmental effects resulting from the operation of each viable control alternative. Example environmental impacts may include additional water discharge and consumption, collateral emission increases, as well as disposable solids and waste generation.

As previously discussed, the typical good combustion measures taken to minimize the formation of CO, namely higher combustion temperatures, additional excess air, and optimum air/fuel mixing during combustion, are often counterproductive to the control of NO_X emissions. A proper balance of this phenomenon is a necessary task in obtaining and complying with the manufacturer's guarantees, since overly aggressive CO limits can jeopardize NO_X emissions design considerations.

The third and final impact analysis addresses the economics of the proposed control technologies in order to evaluate and compare two or more alternatives. This analysis is performed to assess the cost to purchase and operate the control technology. The capital and operating/annual cost is estimated based on the established design parameters. Information for the design parameters is obtained from established reference sources. Documented assumptions can be made in the absence of available information for the design parameters. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost-effectiveness ($/tons) of the control technology is determined. Cost-effectiveness is used to assess the economic cost to achieve the required emissions reduction in the most economical manner. Two types of cost-effectiveness are considered in a BACT analysis; average and incremental cost-effectiveness. Average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option, in units of dollars/incremental ton removed. The incremental cost-effectiveness is a useful measure of economic viability when comparing technologies that have similar removal efficiencies.

Since there is only one feasible control technology to limit the emissions of CO from Units 1 and 2, a comparative cost analysis is not applicable.

Step 5: Select BACT

The highest ranked control technology from Step 3 that is not eliminated in Step 4 based on unacceptable economic, energy, or environmental impacts, is proposed as BACT for the pollutant and emission unit under review. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site- and/or project-specific consideration of the aforementioned screening criteria (e.g., technical, energy, environmental, and economic considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration. BACT cannot be determined to be less stringent than the emissions limits established by an applicable NSPS for the affected air emission source. The only NSPS Subparts that apply are D and Da, neither of which establishes emission limits for CO.

Based on the preceding BACT analysis, GRDA proposes the only feasible control; GCC, for the control of CO emissions resulting from the LNB/OFA Project for CFC Units 1 and 2. The proposed BACT for CO on Units 1 and 2 is good combustion controls to achieve an emission limit of 0.17 lb/MMBtu, based on a 30-day rolling average.

The proposed BACT determination is supported by the USEPA RBLC Clearinghouse database review presented earlier, where good combustion control practices and an average BACT determination of 0.268 lb/MMBtu for recently permitted LNB/OFA retrofit projects are documented as BACT for CO.

B. Evaluation of existing air quality and determination of monitoring requirements

Model Selection and Description

Consistent with the available modeling applications provided for by Appendix W to Part 51 Guideline on Air Quality Models, the AERSCREEN (Version 11126) air dispersion model is used to predict maximum ground-level concentrations associated with the proposed Project's emissions. On April 11, 2011, the USEPA issued a clarification memo stating that AERSCREEN was intended to replace the SCREEN3 model as the recommended screening model. AERSCREEN is a screening version of the AERMOD model, the preferred short-range air dispersion model. AERSCREEN is a single source Gaussian plume model that provides worst-case 1-hour concentrations for a variety of source types. The AERSCREEN model also includes conversion factors to estimate worst-case 3-hour, 8-hour, 24-hour, and annual concentrations.

The AERSCREEN model is used to determine the maximum predicted ground-level concentration for CO for each applicable averaging period resulting from the emissions of the proposed Project.

Source Input Parameters

A series of stack tests for both Units 1 and 2 were performed at CFC in November, 2001. The averages of the stack gas volumetric flow and temperature results from these tests are used in the modeling analyses. The GEP stack heights for both Units 1 and 2 are 505 ft as discussed below. The modeled CO emission rate is conservatively based on a 0.30 lb/MMBtu emission rate and each unit's heat input of 5,131 MMBtu/hr and 5,296 MMBtu/hr for Units 1 and 2, respectively. This modeled emission rate is conservatively high and protective of the air quality standards, because the BACT emission limit for Units 1 and 2 is 0.17 lb/MMBtu.

Stack parameters and pollutant emission rates used in the following modeling analysis.

Source	UTM Easting [1] (m)	UTM Northing [1] (m)	Base Elevation [2] (ft)	GEP Stack Height [3] (ft)	Stack Diameter (ft)	Exhaust Flow Rate [4] (acfm)	Exit Velocity[5] (ft/s)	Exit Temp. [4] (°F)	CO Emission Rate [6] (lb/hr)
Unit 1	294,133.01	4,007,350.57	622	505	20	1,839,483	98	301	1,539.3
Unit 2	294,203.19	4,007,270.52	622	505	20	1,895,063	101	194	1,588.8

1. Universal Transverse Mercator (UTM), Zone 15. NAD83 datum.
2. Base elevation is elevation above mean sea level (amsl).
3. GEP stack heights for both Units 1 and 2 are 505 ft based on the USEPA equation.
4. The exhaust flow rate and temperature values were obtained from averaging the results of the tests that were performed at the CFC in November, 2001.
5. The exit velocity was calculated using the exhaust flow rate and stack diameter values.
6. Emissions from these units are based on a 0.30 lb/MMBtu emission rate and Unit's 1 and 2's heat input rate of 5,131 MMBtu/hr and 5,296 MMBtu/hr, respectively.

Good engineering Practice and Building Downwash Evaluation

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model-predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in OAC 252:100-8-1.5. GEP stack height is defined as the greater of 65 meters or a height established by applying the formula Hg = H + 1.5L, where

Hg = GEP stack height,

H = height of nearby structures, and

L = lesser dimension (height or projected width) of nearby structures,

or by a height demonstrated by a fluid model or a field study that ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features. Because a fluid model analysis or a field study was not completed, the GEP stack height is defined by definition 1 or 2. The term "nearby" is further defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. The stacks for both Units 1 and 2 are built to a height of 505 feet above grade. The facility's calculated GEP stack height based on the equation referenced in OAC 252:100-8-1.5 is 505 feet above grade. Since Units 1 and 2's stack heights are set to GEP, the effects of building downwash will not be included.

Meteorology and Surface Characteristics

The AERSCREEN model incorporates the stand-alone MAKEMET program to generate the matrix of meteorological conditions. The matrix of meteorological conditions is based on site-specific surface characteristics, ambient temperatures, minimum wind speed, and anemometer height. The site-specific surface characteristics are based on output from the pre-processer AERSURFACE program, which utilizes the 1992 USGS National Land Cover Dataset to determine the site-specific surface characteristics. Minimum and maximum temperatures of -25 °F and 114 °F are based on the climatological summary from the Pryor Mesonet station. EPA default values of 0.5 m/s and 10 m are used for minimum wind speed and anemometer height, respectively. Further details about AERSURFACE follow.

USEPA guidance supports the use of AERSURFACE to process land cover data to determine the surface characteristics (i.e., surface roughness, Bowen ratio, and albedo) for the meteorological measurement site that is used to represent meteorological site conditions. Chapter 2.3.4 of ODEQ's *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits* also indicates that surface characteristics using AERSURFACE can be used for air permit applications. The current version of AERSURFACE (Version 08009) supports the use of land cover data from the USGS National Land Cover Data 1992 archives (NLCD92). This analysis obtains digitized NLCD92 data from the USGS National Map Seamless Server. The GeoTIFF file for Oklahoma containing the land cover data is used as input for AERSURFACE. ODEQ's modeling guidance document also recommends the following input conditions for running AERSURFACE:

- Center the land cover analysis on the meteorological measurement site (the Pryor Oklahoma Mesonet Site).
- Analyze surface roughness within 1 km of measurement site.
- Utilize one sector determining the surface roughness length.

- Temporal resolution of the surface characteristics should be determined on a monthly basis.
- The region does not experience continuous snow cover for most of the winter.
- The Mesonet site is not considered an airport.
- The region is not considered an arid region.
- Utilize the default season assignment (winter=Dec, Jan, Feb; Spring=Mar, Apr, May; Summer=Jun, Jul, Aug; Fall=Sep, Oct, Nov)

Because actual observed meteorological data is not used in the screening modeling analysis (i.e., MAKEMET is utilized to create the worst-case meteorological conditions), surface moisture conditions for the Bowen Ratio cannot be assigned to specific years. Therefore, AERSURFACE is run for each of the three surface moisture conditions (i.e., average, dry and wet) to identify surface characteristics associated with the maximum predicted impacts. The following surface characteristic values are used as input to run USEPA's AERSCREEN model.

Month	Surface Roughness Length (m)	Albedo	Bowen Ratio		
			Average	Dry	Wet
Jan	0.021	0.18	0.70	1.92	0.39
Feb	0.021	0.18	0.70	1.92	0.39
Mar	0.031	0.14	0.32	1.02	0.21
Apr	0.031	0.14	0.32	1.02	0.21
May	0.031	0.14	0.32	1.02	0.21
Jun	0.159	0.19	0.47	1.35	0.29
Jul	0.159	0.19	0.47	1.35	0.29
Aug	0.159	0.19	0.47	1.35	0.29
Sept	0.159	0.19	0.70	1.92	0.39
Oct	0.159	0.19	0.70	1.92	0.39
Nov	0.159	0.19	0.70	1.92	0.39
Dec	0.021	0.18	0.70	1.92	0.39

Terrain Considerations

For screening level analyses, the ODEQ requires terrain feature elevations to be included in the dispersion modeling analysis if the terrain within five kilometers of the stack rises to more than 20 percent of the shortest on-site stack being modeled. Since both stacks at the CFC are at base elevation of 622 feet above mean sea level (amsl) and a height of 505 ft, any terrain feature above 723 ft amsl within 5 km requires terrain feature elevations to be included in the dispersion modeling analysis. A review of the NED file within 5 km of the stacks results in terrain elevations above 723 ft; therefore, terrain feature elevations are represented in the dispersion modeling analysis. A NED file, obtained from the USGS representing a 50x50 km domain centered on the center of the two stacks at the CFC, is utilized in the dispersion modeling analysis to incorporate terrain features in AERSCREEN. Based on ODEQ's suggested domain size for refined modeling analyses, a probe distance of 10 km is used in the AERSCREEN modeling analysis.

Urban/Rural Classification

The AERSCREEN model has the option of assigning the specified source to have an urban effect, thus enabling AERSCREEN to employ enhanced turbulent dispersion associated with anthropogenic heat flux, parameterized by population size of the urban area. Section 8.2.3 of the GAQM provides the basis for determining the urban/rural status of a source. For most applications, the land use procedure described in Section 8.2.3(c) is sufficient for determining the urban/rural status. However, there may be sources located within an urban area, but located close enough to a body of water to result in a predominantly rural classification. In those cases, the population density procedure may be more appropriate. Because the CFC facility is not located within an urban area near a body of water, only the following land use procedure is used to assess the urban/rural status of the source.

- Classify the land use within the total area, A_o, circumscribed by a 3-km radius circle about the source using the meteorological land use typing scheme proposed by Auer.
- If land use Types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (single-family compact residential), and R3 (multifamily compact residential) account for 50 percent or more of A_o, use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

Based on visual inspection of the USGS 7.5-minute topographic map of the Project site location, it was conservatively concluded that over 50 percent of the area surrounding the Project may be classified as rural. Accordingly, the rural dispersion modeling option is used in the AERSCREEN model.

Minimum Ambient Distance

The AERSCREEN model allows the user to input the minimum distance to ambient air. Ambient air is defined in 40 CFR 50.1(e) as that portion of the atmosphere, external to buildings, to which the general public has access. Unit 2's stack is the closest to the facility's security boundary (i.e., that area to which public access is physically restricted); therefore, this distance is used as the minimum distance to ambient air in the AERSCREEN modeling analysis. For non-volume sources, which is the case for this Project, the AERSCREEN model cannot model an impact less than 1 meter; however, the CFC's minimum distance to ambient is 1,012 ft (308 m), as such, the 1,012 ft value is utilized in the modeling analysis.

Discrete and Flagpole Receptors

The AERSCREEN model allows the user to have the model calculate impacts at user defined discrete and/or flagpole receptors. Discrete receptors are those that are placed at precise locations that may be of interest due to their sensitive nature. Flagpole receptors are receptors that are located above ground level. The ODEQ Air Dispersion Modeling Guidelines does not mention the application of any discrete or flagpole receptors; therefore, no discrete or flagpole receptors are used in the modeling analysis.

Dispersion modeling analysis usually involves two distinct phases; a preliminary analysis and a full impact analysis. The preliminary analysis models only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emissions increase of a pollutant from a proposed modification. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis, involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed Project. Specifically, the preliminary analysis:

- determines whether the applicant can forego further air quality analyses for a particular pollutant;
- may allow the applicant to be exempted from the ambient monitoring data requirements; and
- is used to define the impact area within which a full impact analysis must be carried out.

In general, the full impact analysis is used to project ambient pollutant concentrations against which the applicable NAAQS and PSD increments are compared, and to assess the ambient impact of non-criteria pollutants. The full impact analysis is not required for a particular pollutant when emissions of that pollutant would not increase ambient concentrations by more than the applicable significant impact level (SIL).

Because the AERSCREEN model used to perform the SIL analysis is a single source model, each unit was run individually. The resulting impacts were conservatively aggregated regardless of time and space to determine the Project's impact. The AERSCREEN model allows the applicant to choose from three different surface moisture categories for the Bowen ratio surface characteristic value, as discussed previously. All three surface moisture categories were modeled, and the Project's maximum model-predicted impacts are presented below. As the results indicate, the Project's model-predicted air quality impacts are less than the modeling significance levels, indicating that the Project is not subject to additional cumulative source air dispersion modeling analyses as part of the PSD review process.

Averaging Period and Scenario	Model-Predicted Impact (µg/m^3)			PSD Class II Significant Impact Level (µg/m^3)	PSD Class II Significant Monitoring Concentration (µg/m^3)
	Unit 1	Unit 2	Project[a]		
8-hr average	126.5	155.0	281.5	500	575
8-hr dry	120.5	164.8	285.3		
8 hour wet	132.7	162.0	294.7		
1-hr average	140.6	172.2	312.8	2,000	--
1-hr dry	133.9	183.2	317.1		
1 hour wet	147.5	179.9	327.4		

C. Evaluation of PSD increment consumption

Because the project impact is less than the SIL, increment consideration is not necessary. In any event, there is no increment for CO.

D. Analysis of compliance with National Ambient Air Quality Standards (NAAQS)

Because the project impact is less than the SIL, further analysis is not necessary.

E. Ambient air monitoring

According to OAC 252:100-8-33(c), if the proposed Project's maximum predicted concentration for a pollutant is less than the applicable PSD significant monitoring concentration, then an exemption from pre-application monitoring requirements can be requested for that pollutant. Because the preceding table shows that the Project's maximum-modeled predicted CO 8-hour impact is less than the PSD significant monitoring concentration, the applicant requests exemption from PSD pre-application monitoring requirements.

F. Evaluation of source-related impacts on growth, soils, vegetation, visibility

The facility has provided an extensive review of these topics, which is presented here verbatim, with only minor formatting changes.

Commercial, Residential, and Industrial Growth Analysis

The Project is located in Mayes County in an area zoned as industrial. Because the Project will not create additional generating capacity, the Project will not have a significant effect upon the industrial growth in the immediate area. There will be an increase in the local labor force during the construction phase of the Project. It is anticipated that most of the labor force during the construction phase will commute from nearby communities. This labor force increase will be temporary, short-lived, and will not result in permanent commercial and residential growth occurring in the vicinity of the project.

The potential for housing shortages and thus the possibility of housing related growth and secondary air quality impacts have been an issue historically for the construction of large coal plants in sparsely populated areas. However, experience has also shown that smaller projects (modifications) like the proposed Project located in or near urban areas typically have no noticeable impacts on the housing market. The reason is that impacts are primarily a function of the size of the construction workforce and the need for the workforce to relocate during construction.

The need to relocate is a function of the available workforce within a reasonable commuting distance of the work site. Research by the Electric Power Research Institute (EPRI) has indicated that the construction workforce for a power plant project can reasonably be expected to commute without relocating during construction from a distance of more than 70 miles, with instances of a commuting distance of more than 100 miles found in each of the construction projects studied. When a 70 mile radius around the CFC site is considered, metropolitan areas including Tulsa and Muskogee in Oklahoma, Joplin, Missouri and Fayetteville, Arkansas are within commuting distance to the site, and a 100 mile radius includes Stillwater, Oklahoma.

The area offers a wide variety of temporary lodging. Given the expected population of the commuting workforce, the fact that during the construction period most workers will be onsite for less than the total construction period, and an abundance of hotel and other short-term lodging options in Mayes County, it is unlikely that a substantial number of the construction workforce would choose to relocate during the construction period. Therefore, the anticipated housing growth will be minimal or nonexistent, and is not expected to have a significant impact on the air quality.

Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. Since there will be no or only minimal number of new, permanent jobs created by the Project, secondary residential, commercial, and industrial growth is not expected to have a significant impact on the air quality.

Finally, because the maximum model-predicted CO concentrations for the proposed Project are well below the NSR/PSD significant impact levels, air concentrations in the region are expected to fully comply with the ambient air quality standards when the proposed Project becomes operational. Therefore, from an air quality impact standpoint, the proposed Project is consistent with the balanced growth demonstrated by the county to date.

Visibility Impairment Analysis

An additional impacts visibility analysis may be used to determine if the emissions increases associated with a proposed PSD project will have an impact on Class II sensitive areas such as state parks, wilderness areas, or scenic sites and over looks. However, because the proposed Project does not result in any increase of a visibility impairing pollutant, and because the CFC is not located within 40 km of a sensitive area, an additional impacts visibility impairment analysis is not required for this Project. An explanation of these issues is presented in the following paragraphs.

The screening model VISCREEN can be used to perform a visibility analysis for Class II areas. The VISCREEN model uses emissions of primary particulate matter (PM), nitrogen oxides (NO_X), primary nitrogen dioxide (NO_2), soot (elemental carbon), and primary sulfate (SO_4^-) to determine the visibility impacts from the emissions associated with the proposed Project. However, the only pollutant that results in a significant net emissions increase is CO, which is a non-visibility impairing pollutant. Therefore, the Project is not predicted to negatively impact visibility.

Furthermore, a review of the Class II areas around the CFC does not show any sensitive areas within 40 km. The nearest ODEQ listed sensitive area is the Deep Fork Wildlife Refuge, which is approximately 85 km from the CFC. The Osage Indian Reservation is approximately 64 km from the site, which is the closest state/national park or Indian reservation area to the CFC.

Vegetation Analysis

The NSR Workshop Manual states that the analysis of air pollution impacts on vegetation should be based on an inventory of species found in the impact area, i.e., significant impact area (SIA). Since the emissions from the proposed Project did not result in any exceedances of the significant impact levels; thus no SIA exists. Therefore, an area with a 3-km radius centered at the facility was chosen for this analysis instead. A review of information gathered from topographic maps and aerial photography concluded that there are no state parks or designated sensitive areas within this 3-km area.

The US Department of Agriculture's Natural Resources Conservation Service (NRCS) was utilized to determine the inventory of plant species in a 3-km radius (a 6×6-km area) surrounding the CFC facility. According to the NRCS, there are a total of 733 different plant species that are located within Mayes County (included in Appendix E of the application). For the purpose of defining the quantitative/qualitative impacts from CO emissions, it was conservatively assumed that at least one "sensitive" species is included among the list of 733 plant species and that all 733 plant species are within the 3-km radius of the CFC.

Unlike fauna, CO does not poison vegetation since it is rapidly oxidized to form carbon dioxide which is used for photosynthesis. However, extremely high concentrations can reduce the photosynthetic rate. According to the USEPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals*, hereafter referred to as USEPA Screening Document, for the most sensitive vegetation, a CO concentration of 1,800,000 μg/m^3 (1-week averaging period) could potentially reduce the photosynthetic rate. The maximum model-predicted 1-hour CO impact of 327.4 μg/m^3 produced by the proposed Project is significantly lower than this screening level (even at a conservative 1-hour averaging period). Consequently, no adverse impacts to vegetation at or near the proposed Project are expected from CO emissions.

Soils Analysis

A soil inventory was completed by obtaining a soil survey within the 3-km radius study area surrounding the facility. The soil survey was obtained from the Natural Resource Conservation Service. The different soil survey classification series that were found to be in excess of 1 percent of the total land area of the 3-km study area are listed in the following table. A complete breakdown of the percentage of each soil survey classification series is provided in Appendix E of the application.

Bates-Collinsville complex	Miscellaneous water
Choteau silt loam	Parsons silt loam
Clarksville gravelly silt loam	Pits
Collinsville loam	Quarles silt loam
Dennis silt loam	Britwater silt loam
Eram-Verdigris complex	Summit silty clay loam
Hector-Enders-Linker complex	Taloka silt loam
Hector-Enders complex	Urban land
Hector-Steprock-Rock outcrop complex	Verdigris silty clay loam
Lenapah silty clay loam	Water
Lenapah-Rock outcrop complex	

As noted earlier, the maximum model-predicted ambient concentration of CO resulting from the Project is 327.4 μg/m^3, which is significantly less than the applicable ambient air quality standards and the NSR/PSD significant impact levels. Because the predicted CO air quality impacts resulting from the Project are not significant, and are in fact orders of magnitude less than the applicable air quality standards designed to protect public health, it is reasonable to conclude that the proposed emissions of CO will not affect soils.

G. Evaluation of Class I area impact

Federally designated Class I areas are afforded special protection in the air permitting process. Generally, Class I area analyses are conducted only for Projects located within 100 km of a Class I area. The CFC is approximately 165 km from the closest Class I area Upper Buffalo Wilderness Area in Arkansas. Other Class I areas in relatively close proximity to the CFC include the Caney Creek Wilderness Area also located in Arkansas, Hercules-Glades Wilderness Area in Missouri, and the Wichita Mountains Wilderness Area in Oklahoma, located approximately 220 km, 210 km, and 340 km from the CFC, respectively. As the proposed

Project results in a substantial decrease in NO_X emissions and no increase in any other visibility impairing pollutants (i.e., SO_2, PM_{10}, and H_2SO_4), a Class I area analysis is not required for this Project.

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 listed in OAC 252:100, Appendix Q. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards. In addition, proposed facility emissions modeled in the construction application demonstrate that the current project will not have a significant impact on air quality.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [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 were submitted and fees paid for previous years as required.

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 that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I 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 Part 70 operating permit, from information in the construction permit application, or are 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 (PM)) [Applicable]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-19 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. There is no change in applicability or in compliance demonstration from that presented in the current Part 70 operating permit, because there will be no changes in PM emissions.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that 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. There is no change in applicability or in compliance demonstration from that presented in the current Part 70 operating permit.

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. There is no change in applicability or in compliance demonstration from that presented in the current Part 70 operating permit.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
<u>Part 5</u> of the subchapter sets “new” equipment standards that limit SO_2 emissions to 0.2 lb/MMBTU for gas fuel, 0.8 lb/MMBTU for liquid fuel, and 1.2 lb/MMBTU for solid fuel. There is no change in applicability or in compliance demonstration from that presented in the current Part 70 operating permit, because the project to control emissions of NO_X is expected to have little or no effect on emissions of SO_2.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter affects “new” combustion sources that exceed 50 MMBTUH. Limits are set at 0.20 lb/MMBTU for gaseous fuels, 0.30 lb/MMBTU for liquid fuels, and 0.70 lb/MMBTU for solid fuels, all as 3-hour averages. All such units at this facility currently meet the requirements.

Anticipated reductions in NO_X emissions will result in a factor of 0.17 lb/MMBTU (30-day rolling average) for Units 1 and 2 after completion of the project, and should easily satisfy the 0.70 lb/MMBTU (3-hour average) standard.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
This subchapter affects gray iron cupolas, blast furnaces, basic oxygen furnaces, petroleum catalytic cracking units, and petroleum catalytic reforming units. There are no affected sources.

OAC 252:100-37 (Volatile Organic Compounds) [Only Part 7 Applicable to this Project]
Part 3 requires storage tanks constructed after December 28, 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. No changes are proposed.
Part 5 limits the VOC content of coating used in coating lines or operations. This facility will not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is not an affected operation.
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. Extensive monitoring of generating unit stack emissions is performed, and is adequate to assure compliance with the requirements of OAC 252:100-37-36. The proposed project is not expected to affect emissions of VOC.

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 Source Permits	not in source category
OAC 252:100-10	General Operating Permit	not in source category
OAC 252:100-11	Alternative Reduction	not requested
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 252:100-39	Nonattainment Areas	not in a subject area
OAC 252:100-47	MSW Landfills	not in source category

SECTION IX. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The Coal-Fired Complex is a major stationary source and the proposed construction permit is subject to New Source Review. The facility is in an attainment area and is required to undergo analysis if the project is a significant modification. The analysis is found in Section VII above.

NSPS, 40 CFR Part 60 [No Change in Applicability]
Only those subparts potentially affected by the current project are considered.
Subpart D (Fossil Fuel-Fired Steam Generators) establishes emission standards for particulate matter, sulfur dioxide, and nitrogen oxides for affected sources with a design heat input capacity greater than 250 million Btu/hr (MMBTUH) that commence construction, reconstruction, or modification construction after August 17, 1971. Unit 1 has heat input capacity of 5,131 MMBTUH threshold, commenced construction on March 1, 1978, and is an affected source. The current project must be analyzed as to whether it constitutes construction, reconstruction, or modification under the subpart. The proposed emissions control upgrade plan is clearly not considered construction of a new electric utility steam generating unit. Reconstruction under the NSPS definition found at 40 CFR 60.15 means the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Under this definition, the proposed activities are clearly not considered to be reconstruction. The definition of modification found in 40 CFR 60.14 states that any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification. Because CO is the only pollutant estimated to have an emissions increase, while the covered pollutants particulate matter, sulfur dioxide, and nitrogen oxides will not increase, the project is not considered a modification under NSPS. Because the current project does not meet the NSPS definitions of construction, reconstruction, or modification, it will not affect the current NSPS applicability status of the facility.
Subpart Da (Electric Utility Steam Generating Units) establishes emission standards for particulate matter, sulfur dioxide, and nitrogen oxides for affected sources with a design heat input capacity greater than 250 million Btu/hr (MMBTUH) that commenced construction after

September 18, 1978. Unit 2 has rated heat input of 5,296 MMBTUH, commenced construction on March 24, 1982, and is an affected source. An argument parallel to that shown above for Unit 1 under Subpart D demonstrates that the current project will not affect the current NSPS applicability status of the facility.

NESHAP, 40 CFR Part 61 [No Change in Applicability]
There are no subparts potentially affected by the current project.
NESHAP, 40 CFR Part 63 [No Change in Applicability]
There are no subparts potentially affected by the current project.

Compliance Assurance Monitoring (CAM), 40 CFR Part 64 [No Change in Applicability]
The current project has no effect on the applicability of this Part. No pollutants that were subject to CAM will drop below appropriate thresholds, and no pollutant not already subject to CAM will have increases of emissions. The low-NO_X burner/overfire air controls being added are not active or add-on controls.

Accidental Release Prevention, 40 CFR Part 68 [No Change in Applicability]
The current project has no effect on the applicability of this Part. The project will not add or delete any materials subject to this Part.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [No Change in Applicability]
Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [No Change in Applicability]
Acid Rain, 40 CFR Part 76 (Phase II NOx requirements) [No Change in Applicability]
Separate renewal Acid Rain Permit No. 2009-435-ARR2 was issued on March 3, 2010. The permit contains SO_2 allowances as published in 40 CFR 73.10. NO_X requirements in accordance with regulations implementing Section 407 of the Clean Air Act are incorporated.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [No Change in Applicability]
Certification testing has been completed for the CEM system required for each unit, and the EPA issued a certification for Units 1 and 2 on February 3, 1997.

Stratospheric Ozone Protection, 40 CFR Part 82 [No Change in Applicability]
This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this Part, nor does this facility perform service on motor (fleet) vehicles that involves ozone-depleting substances. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

SECTION X. COMPLIANCE

Testing

Regardless of the various monitoring options with respect to NO_X offered under NSPS Subparts D and Da, the facility has CEMs required by Part 75 that can be used to verify NO_X emissions. Reference method testing will be required to verify emissions of carbon monoxide.

Tier Classification and Public Review

This application has been classified as **Tier II** based on the request for a construction permit at an existing major source. Public notice of filing of this application was published in The Daily Times (in the Mayes county town of Pryor) on April 1, 2012. The application was available for review at the Pryor Library at 505 E. Graham, Pryor, OK 74361, and at the Oklahoma City office of the Air Quality Division. Notice of availability of the draft permit was published The Daily Times on June 10, 2012, and the draft was available at the same locations as listed for the application. This facility is located within 50 miles of the borders of contiguous states. Notice of availability of the draft permit was provided to the states of Arkansas and Missouri. GRDA requested concurrent public and EPA review. No comments were received from the public, but the EPA had comments as follow.

Comment #1

Paragraph two of PDF Page 4/49 describes the methods used to determine the baseline actual emissions from the two Combustion Sources Unit 1 and Unit 2. Please provide all details such as the periods for which AP-42 Natural Gas Combustion Tables and Coal Combustion Tables were used for calculating emissions. It is noted that NG is used only for ignition.

Response

Comment 1 concerns the presentation of data and underlying detail. All of the information requested is present in the text and tables. The following table presents all data in a single format, so that connections may more easily be seen. Detailed calculations of each value are presented in Appendix B of the application, but they are quite extensive, and would add little to the reader's understanding of the memorandum. As may be seen from the tables in the appendix, gas represents slightly more than 0.1% of all BTUs consumed. Of course, emissions of each pollutant from gas and coal do not vary in this proportion.

<table>
<tr><th>Pollutant</th><th>Baseline period</th><th>Unit #</th><th>Fuel</th><th>Factor used</th></tr>
<tr><td rowspan="4">CO</td><td rowspan="4">2/07 – 1/09</td><td rowspan="2">1</td><td>Coal</td><td>AP-42, Table 1.1-3</td></tr>
<tr><td>Gas</td><td>AP-42, Table 1.4-1</td></tr>
<tr><td rowspan="2">2</td><td>Coal</td><td>Stack test 8/1986</td></tr>
<tr><td>Gas</td><td>AP-42, Table 1.4-1</td></tr>
<tr><td>NO_X</td><td>12/09 – 11/11</td><td>1 & 2</td><td>All</td><td>CEMs</td></tr>
<tr><td>PM</td><td rowspan="7">2/07 – 1/09</td><td rowspan="3">1</td><td rowspan="3">Coal</td><td>Stack test 12/1981</td></tr>
<tr><td>PM_{10}</td><td>See note 1</td></tr>
<tr><td>$PM_{2.5}$</td><td>AP-42, Table 1.1-6</td></tr>
<tr><td>PM/ PM_{10}/ $PM_{2.5}$</td><td>1 & 2</td><td>Gas</td><td>AP-42, Table 1.4-2</td></tr>
<tr><td>PM</td><td rowspan="3">2</td><td rowspan="3">Coal</td><td>Stack test 8/86</td></tr>
<tr><td>PM_{10}</td><td>See note 1</td></tr>
<tr><td>$PM_{2.5}$</td><td>AP-42, Table 1.1-6</td></tr>
<tr><td>SO_2</td><td>3/08 – 2/10</td><td>1 & 2</td><td>All</td><td>CEMs</td></tr>
<tr><td rowspan="2">VOC</td><td rowspan="2">3/07 – 2/09</td><td rowspan="2">1 & 2</td><td>Coal</td><td>AP-42, Table 1.1-19</td></tr>
<tr><td>Gas</td><td>AP-42, Table 1.4-2</td></tr>
<tr><td>Lead</td><td>3/07 – 2/09</td><td>1 & 2</td><td>Coal</td><td>AP-42, Table 1.1-18</td></tr>
</table>

			Gas	AP-42, Table 1.4-2
H_2SO_4	12/07 – 11/09	1 & 2	All	See note 2
Fluorides	3/07 – 2/09	1 & 2	All	See note 3
GHG (mass)	1/10 – 12/11	1 & 2	All	See note 4
GHG (CO_2e)	1/10 – 12/11	1 & 2	All	40 CFR 98, Table A-1

1) The PM_{10} fraction of all PM is taken from the Profile For Coal-Fired Power Plant With ESP found in the EPA Air Emissions Species Manual, Volume II (EPA 450/2-90-001b, 1/90).
2) Calculation of sulfuric acid mist assumes 1% stoichiometric conversion of SO_2 to acid mist.
3) Fluorides are calculated based on the weight ratio of HF to fluorine. HF emissions are based on stack test data.
4) GHG calculations are based on extensive data recited in the narrative three paragraphs before the table under discussion.

Comment #2

The difference between the PAE and EE of NOX given as PEI on the table on PDF Page 9/49 is shown as -8,197 tpy. It should be corrected to -7,897 tpy.

Response

Comment 2 concerns a typo. As seen in previous tables, the correct PAE number for NO_X should have been shown as 7,242, so the difference remains -8,197 TPY.

Fee Paid
Major source construction modification permit fee of $5,000.

SECTION XI. SUMMARY

Ambient air quality standards are not threatened at this site. There is a single active Air Quality compliance and enforcement issue concerning this facility; an RFI for CEMs data and AEI calculations for 2010 and 2011. Issuance of the construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Grand River Dam Authority **Permit Number 2009-179-C (M-2) (PSD)**
Coal-Fired Power Plant (Units 1 and 2)

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on March 6, 2012. The Evaluation Memorandum dated August 1, 2012, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

Specific Conditions are listed using the numbering currently used in Part 70 operating permit No. 2009-179-TVR2 (M-1). Any condition not listed here is unchanged from the way it appears in the Part 70 permit.

1. Points of emissions and emissions limitations for each point. When these limitations conflict with those of Specific Condition No. 5 below, the more stringent limitation applies. Particulate emissions, whether PM, PM_{10}, or $PM_{2.5}$, unless otherwise indicated, should be assumed to apply to State of Oklahoma standards, namely, total PM in that category, otherwise described as the sum of filterable and condensable or front-half and back-half.
[OAC 252:100-8-6(a)]

Equipment and emissions authorized under existing operating permit 2009-179- TVR2 for EUG 1, EUG 4, EUG 5, EUG 6, EUG 7, and Insignificant Activities, are not altered by this construction permit and remain as stated in the existing permit.

EUG 2 Combustion Sources Unit 1

EU	Point	Make/National ID#	MW	MMBtu/hr	Const Date
B-02	1	Foster-Wheeler #6844	490	5,131	3/1/78

All emission limits remain as stated in Part 70 renewal permit 2009-179-TVR (M-1), except for carbon monoxide, which is authorized in this permit at 872 lb/hr and 3,820 TPY. A 30-day rolling average limit of 0.17 lb/MMBtu applies to emissions of CO.

EUG 3 Combustion Sources Unit 2

EU	Point	Make/National ID#	MW	MMBtu/hr	Const Date
B-02	2	Foster-Wheeler #6905	520	5,296	3/24/82

All emission limits remain as stated in Part 70 renewal permit 2009-179-TVR (M-1), except for carbon monoxide, which is authorized in this permit at 900 lb/hr and 3,943 TPY. A 30-day rolling average limit of 0.17 lb/MMBtu applies to emissions of CO.

2. Compliance with the authorized emission limits of Specific Condition 1 shall be demonstrated by adherence to the operating scenarios described as follows. The **Base Scenario** for Units 1 and 2 consists of operating on coal with occasional use of natural gas from the igniters for flame stabilization. Boiler 1 uses only Wyoming (sub-bituminous) coal, while Boiler 2 is designed to use 90% Wyoming coal and 10% Oklahoma (bituminous) coal, with the ratio based on heating value. Unit 2 may operate on 100% Wyoming coal. The **Alternative Scenario** for Units 1 and 2 consists of operating on “refined coal” with occasional use of natural gas from the igniters for flame stabilization. Specific Condition #4 describes refined coal and establishes conditions for its use. The auxiliary boilers are designed to operate on distillate (No. 2 fuel oil), with igniters designed to operate on propane. Sulfur dioxide emissions for distillate assume maximum sulfur content of $0.05\%_W$. [OAC 252:100-8-6(a)]

18. 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 252:100-43]

a. Total usage of each type of fuel, including Wyoming coal for Unit 1, each of Wyoming and Oklahoma coal for Unit 2, refined coal (including the amounts of MerSorb and S-Sorb), for Units 1 and 2, distillate and propane for each auxiliary boiler, and natural gas use for Unit 1 and Unit 2 igniters, and all other materials burned or disposed of in the boilers (monthly and cumulative annual).
b. Sulfur content of diesel fuel. This condition may be satisfied by maintaining a vendor’s statement that the fuel complies with the facility’s $0.05\%_W$ sulfur specification.
c. Emissions data as required by the Acid Rain Program.
d. RATA test results from periodic CEMS certification tests.
e. Operating hours for Units 1 and 2 and for auxiliary boilers 1 and 2.
f. Unit 2 ESP inspection reports, per Specific Condition #8.
g. All CAM records required per Specific Condition #10.
h. Records necessary to demonstrate that the proportions per ton of coal of S-Sorb and MerSorb used do not exceed the limits authorized by Specific Condition #4.
i. Records necessary to demonstrate compliance with OAC 252:100-36.2(c)(3). Emission points included are: EUG 2; EUG 3; TO-03 points 13, 14, and 26 -31 of EUG 5; BL-06, BU-06, FL-05, and FU-05 of EUG 6; and VT-07 points 1 and 2 and VT-08 points 1 and 2 of EUG 7.

20. Performance testing per 40 CFR 60.8 for compliance with carbon monoxide (Reference Method 10B) emission limits established in Specific Condition #1 shall be performed for each unit within 180 days of installation of LNB/OFA on the unit. [OAC 252:100-43]

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]

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 Number: 2009-179-C (M-2) (PSD)

Grand River Dam Authority,

having complied with the requirements of the law, is hereby granted permission to add low-NO_X burners and overfire air as pollution control equipment to Unit 1 and Unit 2 at the Coal-Fired Electric Generating Facility near Chouteau, Mayes County, OK,

subject to standard conditions dated July 21, 2009, and specific conditions, both attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date below, except as authorized under Section VIII of the Standard Conditions.

Eddie Terrill, Director **Date**

Charles Barney, Assistant General Manager
Grand River Dam Authority
P.O. Box 609
Chouteau, OK 74337

Permit Number: **2009-179-C (M-2)(PSD)**
Permit Writer: Herb Neumann
Date: August 1, 2012

Dear Mr. Barney:

Enclosed is the permit authorizing construction of the Low-NO_X Burner/Over Fire Air project at the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions that are attached.

Also note that you are required to annually submit an emission inventory for this facility. An emission inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emission Inventory Staff at 405-702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact our office at (918) 293-1600. Air Quality personnel are located in the DEQ Regional Office at Tulsa, 3105 E. Skelly Drive, Suite 200, Tulsa, OK, 74105.

Sincerely,

Phillip Fielder, Engineering Manager
AIR QUALITY DIVISION