Exhibit 6

DRAFT

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **October 27, 2009**

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

THROUGH: Kendal Stegmann, Senior Environmental Manager
Compliance and Enforcement

THROUGH: Phil Martin, P.E., Engineering Section

THROUGH: Peer Review

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Permit Application No. **2003-400-TVR (M-1)**
Oklahoma Gas & Electric Company
Seminole Generating Station (4911)
Section 25, T6N, R5E, Seminole County
Latitude: 34.9705°N; Longitude: 96.7335°W
Located Two Miles Northeast of Konawa

SECTION I. INTRODUCTION

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

SECTION II. FACILITY DESCRIPTION

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

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

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

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

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

SECTION III. EQUIPMENT

EUG 1 Facility Wide

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

EUG 2 Boilers

EU ID#	Point ID#	EU Name/Model	Heat Capacity (MMBTUH)	Construction Date
2-B	01	Unit 1 Boiler	5,480	1968
2-B	02	Unit 2 Boiler	5,480	1968
2-B	03	Unit 3 Boiler	5,496 (gas fuel) 3,681 (oil fuel)	5/28/70

EUG 3 Auxiliary Boiler

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

EUG 4 Gas Turbine

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

EUG 5 Storage Tanks

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

Stack Parameters

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

SECTION IV. EMISSIONS

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

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

SCENARIO I: GAS FUEL

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

SCENARIO II: OIL FUEL (BOILER 3)

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

FACILITY WIDE HAP EMISSIONS

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

SECTION V. BART ANALYSIS

The Regional Haze Rule requires certain states, including Oklahoma, to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The Regional Haze Rule requires states to submit a plan to implement the regional haze requirements (the Regional Haze SIP). The Regional Haze SIP must provide for a Best Available Retrofit Technology (BART) analysis of any existing stationary facility that might cause or contribute to impairment of visibility in a Class I Area.

BART-eligible sources include the following sources:

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

Seminole Units 1, 2, and 3 are fossil-fuel fired boilers with heat inputs greater than 250 MMBTUH. All three units were in existence prior to August 7, 1977, but not in operation prior to August 7, 1962. Based on a review of existing emissions data, all three units have the potential to emit more than 250 TPY of NO_X, a visibility impairing pollutant. Therefore, Seminole Units 1, 2, and 3 meet the definition of a BART-eligible source.

BART is required for any BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area. EPA has determined that an individual source will be considered to "contribute to visibility impairment" if emissions from the source result in a change in visibility, measured as a change in deciviews (Δ-dv), that is greater than or equal to 0.5 dv in a Class I Area. Visibility impact modeling previously conducted by OG&E determined that the maximum predicted visibility impacts from Seminole Units 1, 2, and 3 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains Class I Area. Therefore, Seminole Units 1, 2, and 3 were determined to be BART applicable sources, subject to the BART determination requirements.

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

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

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

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

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

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

<u>Class I Areas Near the Seminole Station</u>

- Wichita Mountains Wildlife Refuge (WMWR - Oklahoma) 178 km
- Caney Creek Wilderness Area (CCWA - Arkansas) 242 km
- Upper Buffalo Wilderness Area (UBWA - Arkansas) 310 km
- Hercules-Glades Wilderness Area (HGWA - Missouri) 387 km

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

BART Requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

SEMINOLE UNITS 1, 2, AND 3 BART DETERMINATION

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

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

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

Baseline emissions from Seminole Units 1, 2, and 3 were developed based on an evaluation of actual emissions data submitted by the facility pursuant to the federal Acid Rain Program. In accordance with EPA guidelines in 40 CFR 51, Appendix Y, Part III, emission estimates used in the modeling analysis to determine visibility impairment impacts should reflect steady-state operating conditions during periods of high capacity utilization. Therefore, baseline emissions (lb/hr) represent the highest 24-hour block emissions reported during the baseline period. Baseline emission rates (lb/MMBTU) were calculated by dividing the maximum hourly mass emission rates for each boiler by the boiler's full load heat input.

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

	Unit 1		Unit 2		Unit 3	
Pollutant	**lb/hr**	**lb/MMBTU**	**lb/hr**	**lb/MMBTU**	**lb/hr**	**lb/MMBTU**
NO_X	1,859	0.339	1,940	0.354	1,204	0.219

Presumptive BART Emission Rates

In the final Regional Haze Rule, EPA established presumptive BART emission limits for NO_X for certain electric generating units (EGU) based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls. The presumptive limits apply to EGU at power plants with a total generating capacity in excess of 750 MW. For these sources, EPA established presumptive emission limits for coal-fired EGUs greater than 200 MW in size. Because Seminole Units 1, 2, and 3 are natural gas-fired units, the presumptive BART emission limits are not applicable.

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

BART DETERMINATION FOR NITROGEN OXIDES (NO_X)

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

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

Step 1: Identify Potentially Feasible NO_X Control Options

Potentially available control options were identified based on a comprehensive review of available information. NO_X control technologies with potential application to Seminole Units 1, 2, and 3 are listed below.

List of Potential NO_X Control Options

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

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

Step 2: Technical Feasibility of Potential Control Options
NO_X control technologies can be divided into two general categories: combustion controls and post combustion controls. Combustion controls reduce the amount of NO_X that is generated in the boiler. Post-combustion controls remove NO_X from the boiler exhaust gas. The technical feasibility of each potentially applicable NO_X control technology, with respect to natural-gas fired boilers, is evaluated below.

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

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

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

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

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

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

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

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

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

<u>Flue Gas Recirculation (FGR)</u>
FGR controls NO_X by recycling a portion of the flue gas back into the primary combustion zone. The recycled air lowers NO_X emissions by two mechanisms: (1) the recycled gas, consisting of products which are inert during combustion, lowers the combustion temperatures; and (2) the recycled gas will reduce the oxygen content in the primary flame zone. The amount of recirculation is based on flame stability. Seminole Unit 3 is currently designed with FGR control.

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

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

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

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

<u>Post-Combustion Controls</u>

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

<u>Selective Non-Catalytic Reduction</u>

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

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

Flue gas temperature at the point of reagent injection can greatly affect NO_X removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,700 °F. At temperatures below the desired operating range, the NO_X reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_X resulting in low NO_X reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor in SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that

temperature window. In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_X ratio, and fuel sulfur content.

SNCR control systems have been installed as retrofit NO_X control systems on small and medium sized coal- and gas-fired boilers; however, SNCR has not been used on large boilers (i.e., boilers larger than approximately 300 MW). Large boilers, including Seminole Units 1, 2, and 3, would present several design problems making it difficult to ensure that the reagent (urea or NH_3) would be injected at the optimum fuel gas temperature and that there would be adequate mixing and residence time.

The physical size of the Seminole boilers makes it technically infeasible to locate and install NH_3 injection points capable of achieving adequate mixing within the required temperature zone. Higher NH_3 injection rates would be needed to achieve adequate mixing. This design would tend to result in relatively high levels of unreacted NH_3 in the flue gas (NH_3 slip). Furthermore, because the Seminole boilers are typically used as peaking units, boiler load is continually changing. Boiler load changes affect flue gas flow rates and temperatures, which would make it particularly difficult to inject the needed quantity of reactant at the requisite temperature.

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

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

<u>Selective Catalytic Reduction</u>

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

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

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

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

SCR has been installed as NO_X control technology on existing gas-fired boilers. Based on emissions data available from the EPA Electronic Reporting website, large gas-fired boilers (with heat inputs above approximately 1,000 MMBTUH) have achieved actual long-term average NO_X emission rates in the range of approximately 0.02 to 0.05 lb/MMBTU. Several design and operating variables will influence the performance of the SCR system, including the volume, age and surface area of the catalyst (e.g., catalyst layers), uncontrolled NO_X emission rate, flue gas temperature, and catalyst activity. Catalyst that has been in service for a period of time will have decreased performance because of normal deactivation and deterioration. Catalyst that is no longer effective due to plugging, blinding or deactivation must be replaced. In addition, flue gas temperature is an important component of SCR effectiveness. SCR control systems on gas-fired units that operate as peaking units would require time to adjust to continuous changes in boiler load, flue gas flow rate, and flue gas temperature.

Based on emission rates achieved in practice at existing gas-fired units, and taking into consideration long-term operation of an SCR control system (including catalyst plugging and deactivation) and the fact that the Seminole boilers typically operate as peaking units, it is anticipated that SCR could achieve a controlled NO_X emission rate of 0.04 lb/MMBTU (30-day rolling average) on Seminole Units 1, 2, and 3. An emission rate of 0.04 lb/MMBTU is equivalent to an average NO_X concentration in the flue gas of approximately 33 ppmvd @ 3% O_2.

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

<u>Rotating Opposed Fired Air (ROFA) and Rotomix</u>
ROFA is a boosted OFA system that includes a patented rotation process which includes asymmetrically placed air nozzles. Like other OFA systems, ROFA stages the primary combustion zone to burn overall rich, with excess air added higher in the furnace to burn out products of incomplete combustion. The ROFA nozzles are designed to increase turbulence within the furnace. Increased turbulence should prevent the formation of stratified laminar flow, enable the furnace volume to be used more effectively for the combustion process, and reduce the maximum temperatures of the combustion zone.

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

ROFA and Rotamix® systems have been demonstrated on smaller boilers but have not been demonstrated in practice on boilers similar in size to Seminole Units 1, 2, and 3. OFA control systems are a technically feasible retrofit control technology and the ROFA design could also be applied on Seminole Units 1, 2, and 3. However, there is no technical basis to conclude that the ROFA design would provide additional NO_X reduction beyond that achieved with other OFA designs. Therefore, ROFA control systems will not be evaluated as a specific control system, but will be included in the overall evaluation of combustion controls (e.g., LNB/OFA).

The Rotamix system is a SNCR control system coupled with the ROFA rotating injection nozzle design. The technical limitations previously discussed, including the physical size of the boiler, inadequate NH_3/NO_X contact, and flue gas temperatures, would apply equally to the Rotamix control system. There is no technical basis to conclude that the Rotamix design addresses these unresolved technical difficulties. Therefore, like other SNCR control systems, the Rotamix system is determined not to be available for Seminole Units 1, 2, and 3 and will not be evaluated further in the BART determination.

<u>Pahlman Multi-Pollutant Control Process</u>

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

The filter cake is pulsed off-line into a wet regeneration process. The regenerated sorbent is stored in liquid form to be employed again via the spray dryer. The captured nitrogen and sulfur can be purified and may be converted into granular fertilizer by-products. To date, bench- and pilot-scale testing have been conducted to evaluate the technology on utility-sized boilers. The

New & Emerging Environmental Technologies (NEET) Database identifies the development status of the Pahlman Process as full-scale development and testing. The process is an emerging multi-pollutant control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large natural gas-fired boiler. It is likely that OG&E would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system on Seminole Units 1, 2, and 3. BART does not require applicants to experience extended time delays or resource penalties to allow research to be conducted on an emerging control technique. Therefore, at this time the Pahlman Process is not considered an available NO_X control system for Seminole Units 1, 2, and 3 and will not be further evaluated in the BART Analysis.

Wet NO_X Scrubbing Systems

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

Wet scrubbing systems have been installed at chemical processing plants and smaller coal-fired boilers. The NEET Database classifies wet scrubbing systems as commercially established for petroleum refining and oil/natural gas production. However the technology has not been demonstrated on large utility boilers and it is likely that OG&E would incur substantial engineering and testing to evaluate the scale-up potential and long-term effectiveness of the system. Therefore, at this time wet NO_X scrubbing systems are not considered available or technically feasible retrofit control systems for Seminole Units 1, 2, and 3 and will not be further evaluated in this BART Analysis.

Technical Feasibility of Potential NO_X Control Technologies

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

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

1 Seminole Unit 3 is currently equipped with FGR control

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

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

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

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

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

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

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

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

Technically Feasible NO_X Control Technologies

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

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

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

Step 4: Evaluate the Technically Feasible NO_X Control Technologies

NO_X Control Technologies – Economic Evaluation

The most effective NO_X retrofit control system, in terms of reduced emissions, that is considered to be technically feasible for Seminole Units 1, 2, and 3 includes combustion controls (LNB/OFA) and post-combustion SCR. This combination of controls should be capable of achieving the lowest controlled NO_X emission rate on an on-going long-term basis. The effectiveness of the SCR system is dependent on several site-specific system variables, including the size of the SCR, catalyst layers, NH_3/NO_X stoichiometric ratio, NH_3 slip, and catalyst deactivation rate. Furthermore, SCR control may not be as effective on boilers that operate as peaking units, as NO_X reduction in an SCR is a function of flue gas temperature. Based on emission rates achieved in practice at similar sources, and including a reasonable margin to account for normal system fluctuations and the fact that the Seminole boilers are operated as peaking units, the combination of combustion controls and SCR should achieve an average controlled NO_X emission rate of 0.04 lb/MMBTU (30-day average). The second most effective NO_X retrofit control system that is considered technically feasible for Seminole Units 1, 2, and 3 includes combustion controls (LNB/OFA+FGR). The combination of LNB/OFA+FGR is expected to achieve an average control efficiency of approximately 40% from baseline on gas-fired units that operate at varying loads and are typically operated as peaking units. The third most effective NO_X retrofit control system considered technically feasible is the combination of LNB/OFA without FGR. This combination of controls is expected to achieve an average control efficiency of approximately 25% from baseline.

Economic impacts associated with the LNB/OFA, FGR, and SCR control systems were evaluated in accordance with EPA guidelines (40 CFR Part 51 Appendix Y). In accordance with guidelines Part III of Appendix Y, emission estimates used in the modeling analysis to determine visibility impairment impacts should reflect steady-state operating conditions during periods of high capacity utilization. Therefore, projected emission rates (lb/hr) were calculated based on the expected controlled emission rate (lb/MMBTU) achievable on a 30-day rolling average and heat input to the boiler at full load.

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

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

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

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

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Cost estimates were compiled from a number of data sources. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Major equipment costs were developed based on publicly available cost data and equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit Seminole Units 1, 2, and 3 with the control technologies. Fixed and variable O&M costs were developed for each control system. Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (e.g., NH_3), byproduct management, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with operation of the new control technology, including operation of any new fans as well as the power requirements for pumps, reagent handling, and by-product handling.

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

Seminole Generating Station - Annual NO_X Emissions

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

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

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

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

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

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

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

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

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

1 Total annual costs for all three units are not additive because Unit 3 is currently equipped with FGR control and Unit 3 has a slightly higher heat input.

2 Incremental cost effectiveness of the FGR system is compared to costs/emissions associated with LNB/OFA controls. Similarly, incremental cost effectiveness of the SCR system is compared to costs/emissions associated with LNB/OFA+FGR controls.

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

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

Equipment costs, retrofit challenges, and annual operating costs all have a significant impact on the annualized cost of SCR control systems. Significant annual operating costs include the energy cost associated with the additional pressure drop across the SCR and costs associated with replacing the SCR catalyst as it degrades over time. Based on projected actual emissions, SCR could reduce overall NO_X emissions from Seminole Units 1, 2, and 3 by ~~-~~approximately 5,513 TPY (compared to combustion controls and FGR); however, the incremental cost associated with this reduction is approximately $44,534,600 per year, or $8,078/ton.

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

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

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

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

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

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

Seminole Generating Station Summary of NO_X BART Impact Analysis

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

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

Step 5: Evaluate Visibility Impacts

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

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

NO_X Visibility Assessment / Visibility Improvement[1]

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

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

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

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

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

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

NO_X Average Visibility Cost Impact Evaluation[1]

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

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

NO_X Incremental Visibility Cost Impact Evaluation

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

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

Proposed BART for NO_X Control at Seminole Units 1, 2, and 3

OG&E is proposing combustion controls and FGR (LNB/OFA+FGR) as BART for Seminole Units 1, 2, and 3. This combination of control technologies represents the most effective technically and economically feasible NO_X retrofit technology for the existing boilers. The combination of proposed combustion controls is expected to reduce NO_X emissions by 40% from existing baseline emissions under all normal boiler operating conditions, including load changes, low load operations, and high load operations. A 40% reduction in emissions from baseline for each unit results in the following controlled NO_X emission rates:

- Seminole Unit 1: 0.203 lb/MMBTU
- Seminole Unit 2: 0.212 lb/MMBTU
- Seminole Unit 3: 0.164 lb/MMBTU

Note that Seminole Unit3 is currently designed with FGR: therefore, emissions from Unit 3 under the FGR control option only include LNB/OFA retrofit controls.

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The average cost effectiveness of LNB/OFA+FGR control systems is estimated to be in the range of $1,675/ton and $18.3 MM/dv/yr. While these cost effectiveness numbers are somewhat higher than EPA's cost estimate for presumptive BART controls on large coal-fired EGUs, they are not of such magnitude as to exclude combustion controls as BART on the gas-fired units at Seminole. The addition of an SCR control system could provide incremental NO_X reductions; however, costs associated with SCR control are significant, and incremental visibility improvements are limited. The average cost effectiveness of SCR control systems on all three units is estimated to be $5,387/ton and $55.75 MM/dv/yr. These costs are significantly higher than the average cost of NO_X control at similar sources. In the BART rule, EPA concluded that the cost of controls to meet the BART NO_X presumptive level on large coal-fired EGUs "in most cases range from just over $100 to $1,000 per ton" (see, 70 FR 39135). The average cost

effectiveness of SCR on Seminole Units 1, 2, and 3 are high because of the relatively low average NO_X emission rates that can be achieved with combustion controls and the fact that Seminole Units 1, 2, and 3 are operated as peaking units (limiting annual mass emissions).

Modeled incremental visibility improvements associated with SCR controls are less than 0.3 Δ-dv at all Class I Areas, except the Wichita Mountains where SCR controls result in a modeled visibility improvement of 0.553 Δ-dv (compared to LNB/OFA+FGR controls). Because of the limited improvement in modeled visibility impacts, the cost effectiveness of SCR control, on a $/dv basis is significant. Furthermore, compared to the costs and modeled visibility impacts associated with LNB/OFA+FGR controls, the incremental cost effectiveness of SCR is estimated to be $8,078/ton and more than $80.5 MM/dv/yr. Both costs are significantly higher than the expected cost of BART controls on large EGUs, and should preclude SCR from consideration as BART.

Proposed BART Permit Limits and Control Technologies

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

SECTION VI. CALPUFF MODELING

Comment [A7]: This section of the memorandum does not reflect the most recent BART determination submitted in May 2008.

Background

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I Areas. The Clean Air Act defines Class I Areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I Area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I Area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

To promote consistency between states in the development of BART modeling protocols and to harmonize the approaches between adjacent RPO, the Central States Regional Air Planning (CENRAP) organization developed BART Modeling Guidelines (December 15, 2005). The intent of the guidelines is to assist CENRAP states and source operators in the development of statewide and source-specific modeling protocols.

The following summarizes the modeling methods and procedures that were followed to conduct a refined CALPUFF modeling analysis for the OG&E Seminole Generating Station. The modeling methods and procedures used to determine appropriate controls for OG&E's BART-eligible sources at the Seminole Generating Station that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I Areas. It was OG&E's intent to determine a combination of emissions controls that would reduce the impact of the Seminole Generating Station to a degree that the 98th percentile of the visibility impact predicted by the modeling due to all of the BART eligible sources at the station was below EPA's recommended visibility contribution threshold of 0.5 Δdv.

Bart-Eligible Sources (Seminole Station)

- Unit 1 - 5,480 MMBTUH Natural Gas Fired Boiler
- Unit 2 - 5,480 MMBTUH Natural Gas Fired Boiler
- Unit 3 - 5,496 MMBTUH Natural Gas Fired Boiler

As required in CENRAP's BART Modeling Guidelines, Class I Areas within 300 km of the Seminole Generating Station were included in the analysis.

CALPUFF Modeling System

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in "puffs." CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

The versions of the CALPUFF modeling system programs that were used for conducting OG&E's BART modeling are listed below.

CALPUFF Modeling System Versions

Processor	Version	Level
TERREL	3.311	030709
CTGCOMP	2.22	030528
CTGPROC	2.42	030709
MAKEGEO	2.22	030709
CALMM5	2.4	050413
CALMET	6.211	060414
CALPUFF	6.112	060412
POSTUTIL	1.4	040818
CALPOST	6.131	060410

Modeling Domain

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. The computational domain was set to extend at least 50 km in all directions beyond the Seminole Generating Station and the Class I Areas of interest. The map projection for the modeling domain was Lambert Conformal Conic (LCC) and the datum was the North American Datum 1927 (NAD-27). The reference point for the modeling domain is Latitude 34ºN, Longitude 100.5ºW. The northeast corner was Latitude 37.25ºN and Longitude 92ºW. The meteorological grid spacing was 3 km.

Vertical Layers

Layer	Cell Face Height (m)
1	20
2	40
3	80
4	160
5	320
6	640
7	1,200
8	2,000
9	3,000
10	4,000

The height of the top vertical layer was set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain was divided into 10 layers. The vertical dimensions were weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

Geophysical Data

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

Terrain Data

Terrain data was obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data was then processed by the TERREL program to generate grid-cell elevation averages across the modeling domain.

Land Use Data

USGS Composite Theme Grid (CTG) format Land Use and Land Cover (LULC) data files at 1:250,000 resolution were used. Where 1:250,000 land use data was not available, USGS data at 1:100,000 resolution was used. The USGS CTG format LULC data files were compressed prior to use in the CTGPROC utility processor using the CTGCOMP program. The LULC data were processed by the CTGPROC program to generate land use for each grid cell across the modeling domain.

Compiling Terrain And Land Use Data

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program were then uploaded into the MAKEGEO program to create a geophysical data file that was used as the input for CALMET.

CALMET

CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET was used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, precipitation data, and mesoscale model output to develop the meteorological fields. Upper air observations were not used in generating the meteorological fields.

MM5 Data

Hourly mesoscale data was used as the initial guess field in developing the CALMET meteorological data. The following 5th generation mesoscale model meteorological data sets (or MM5 data) was used in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR
- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data used were subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. The southern set of the extracted MM5 data was used.

The 2001 southern subset of the extracted MM5 data included 30 files that were broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which were broken into 30 to 31 day increment files (1 file per month). The 2001 to 2003 MM5 data extracted by Alpine Geophysics were not able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM5 data in the EPA approved CALMET program, each of the MM5 files had to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data occurred.

The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary, since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it was necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data was not used directly. Instead the data files were modified by adding eight additional hours of data to the end of each file from the beginning of the subsequent file. CALMET was then run using the appended MM5 data to generate a contiguous set of CALMET output files.

Surface Data

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations was processed for use in CALMET using the SMERGE program.

Missing surface data was filled using procedures recommended by EPA. Missing data periods of 5 hours or less were replaced using these procedures. For periods greater than 5 hours, data was left either unfilled or was not used in CALMET processing. A large enough quantity of surface stations were included in the domain so that overlapping areas of influence would allow data from an alternate station to be used.

The use of multiple stations for meteorological observations in CALMET/CALPUFF provides a substantial enhancement over the steady-state treatment of observations from a single meteorological station. Surface data were extracted from the surface stations. Raw observations from these stations were obtained from the National Climatic Data Center (NCDC). The data was quality assured and then merged using the SMERGE pre-processor to create a single assimilated data file of surface observations for each year analyzed.

Precipitation Data

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it was necessary to include observations of precipitation in the CALMET analysis. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using the PMERGE program.

Upper Air Data

Upper Air observations were not used in the CALMET analysis (i.e. NOOBS=1).

CALMET Control Parameters

The modeling was conducted using the CENRAP recommended parameters, except the ones listed below. A explanation is also provided as to why the CENRAP recommended parameters were not used for these variables. Most of the differences are due to the inclusion of observation data into the modeling analysis.

CALMET Input Variables Where CENRAP Suggested Value was not Used

Variable	Suggested	Used	Description	Reason
DGRIDKM	6.0	3.0	Grid spacing (km)	Refined grid spacing
NN2	1	2	Last time step for debug data to be printed	Generated debug data for 2 time steps
NZPRN2	0	1	# Of levels at surface to print	Default
NOOBS	2	1	No obs mode	Used surface OBS

CALMET Input Variables Where CENRAP Suggested Value was not Used

Variable	Suggested	Used	Description	Reason
NSSTA	0	47	# Met stations in surf.dat	# of stations
NPSTA	0	135	# Met stations in precip.dat	# of stations
IFORMC	2	1	Format cloud data	N/A - no cloud data used
IKINE	0	1	Adjust winds using kinematic effects	Computed kinematic effects
RMAX1	30	100	Max radius of influence over land in surface layer (km)	IWAQM Phase 2 Study
RMAX2	30	500	Max radius of influence over land aloft (km)	IWAQM Phase 2 Study
RMAX3	30	36	Max radius of influence over water (km)	Used MM5 data spacing
R1	1	50	Weighting of 1st guess surface field (km)	IWAQM Phase 2 Study
R2	1	100	Weighting of 1st guess aloft field (km)	IWAQM Phase 2 Study
ITPROG	2	1	3D temp from observations or MM5	Used surface observations

CALPUFF

The CALPUFF model uses the output file from CALMET together with source, receptor, and chemical reaction information to predict hourly concentration impacts.

Source Emissions

Baseline (pre-BART) emission data was based on CEMS data collected by OG&E over the 2001-03 time frame. In accordance with CENRAP guidelines, the emission rate over the highest calendar day (24-hr average) was used to establish baseline emissions. The units at the Seminole Generating Station operate primarily on natural gas and occasionally fuel oil. During the 2001-03 time frame, only Seminole Unit 3 consumed fuel oil. In addition, these units are operated as peaking units, resulting in an operating profile that varies substantially on a daily and a seasonal basis.

Based on CEM data over the 2001-03 time period, modeled emissions are based on the highest hourly emission rate (based on a 24-hour calendar day average) that occurred from 2001 to 2003. In order to accurately reflect the operating profile (i.e., peaking nature) of these units in the CALPUFF model, a variable emission rate data file was utilized (PTEMARB.dat). This emission data file was developed by utilizing the highest 24-hour emission rate for each calendar month over the 2001-03 time frame.

BASELINE 24-HOUR AVERAGE EMISSION RATES

		SO_2	H_2SO_4	NO_X	PM_{10}
EGU	**Month**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**
Unit 1	January	1.99	0.026	941	0.25
	February	1.69	0.025	718	0.21
	March	2.28	0.035	1048	0.29
	April	2.10	0.032	915	0.27
	May	1.95	0.025	936	0.25
	June	2.06	0.032	942	0.27
	July	2.12	0.032	751	0.27
	August	1.98	0.027.	862	0.25
	September	2.15	0.030	860	0.27
	October	1.68	0.026	595	0.22
	November	2.03	0.025	1072	0.26
	December	2.08	0.028	883	0.27
Unit 2	January	1.89	0.012	954	0.25
	February	1.82	0.021	1,103	0.23
	March	1.94	0.024	1,240	0.25
	April	2.21	0.034	1,209	0.29
	May	2.34	0.031	1,196	0.30
	June	2.15	0.033	1,125	0.28
	July	2.33	0.028	1,322	0.30
	August	2.15	0.033	1,285	0.28
	September	2.44	0.028	1,525	0.31
	October	1.98	0.025	1,026	0.26
	November	1.82	0.000	874	0.23
	December	1.83	0.000	982	0.23
Unit 3	January	2.15	0.025	1,184	0.27
	February	1,142.29	25.148	890	0.22
	March	1,145.01	25.207	857	0.21
	April	1.56	0.024	747	0.20
	May	2.25	0.028	1,055	0.29
	June	204.62	4.505	656	0.23
	July	2.20	0.027	1,136	0.28
	August	2.00	0.030	837	0.26
	September	2.44	0.031	1,226	0.32
	October	2.07	0.026	916	0.26
	November	2.55	0.019	808	0.22
	December	2.06	0.032	878	0.26

Emission estimates for various control scenarios were developed by Sargent and Lundy. Since the units at the Seminole Station are natural-gas fired, NO_X control technologies were primarily evaluated in this analysis. OG&E elected to evaluate cost effectiveness on a facility-wide basis (as opposed to a unit-by-unit basis) and will install the final selected control technology on each of the affected units at the facility.

Point Source Stack Parameters

	UTM E	UTM N	Velocity	Height	Diameter	Temp
Unit	**(m)**	**(m)**	**(ft/s)**	**(ft)**	**(ft)**	**(°F)**
Unit 1	707,651	3,871,616	13.58	54.27	4.57	393
Unit 2	707,650	3,871,678	13.58	54.27	4.57	393
Unit 3	707,649	3,871,740	19.85	106.71	5.49	412

The base elevation of each of the units is 290 meters (950 feet) above MSL based on visual inspection of USGS topographic maps. Based on FLM guidance, PM_{10} emissions from natural gas combustion consists of primarily (75%) fine particulate matter (PM_F, considered $PM_{<2.5}$) and (25%) coarse particulate matter (PM_C, considered $PM_{2.5-10}$).

Receptor Locations

The National Park Service (NPS) provides electronic files that include the discrete locations and elevations of receptors to be evaluated in Class I Area analyses. The receptor files for were downloaded from the NPS website, converted into the LCC NAD27 projection, and incorporated into the CALPUFF model.

Background Ozone

Background ozone concentrations were required in order to model the photochemical conversion of SO_2 and NO_X to sulfates (SO_4) and nitrates (NO_3). CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. CENRAP recommended either developing background ozone concentrations from ambient monitors located within the domain being modeled or from the most recent CENRAP CMAQ/CAMx simulation for the 2002 base year. Modeling was conducted using a conservative background concentration of 40 ppb. This is the default background concentration from the CENRAP protocol.

Background Ammonia

Background concentrations of ammonia were required to model the formation of ammonia nitrates and sulfates. CENRAP recommended developing background concentrations from the most recent CENRAP CMAQ or CAMx simulation for the 2002 base year. Since the CMAQ/CAMx modeled and observed monthly averaged concentrations exhibit wide spatial variability and the data is not readily available, a conservative background concentration of 3 ppb was used. This is the default background concentration from the CENRAP protocol.

CALPUFF Model Control Parameters

Puff splitting is a generally accepted option in refined modeling analyses over large model domains for assessing impacts on Class I Areas. However, this option would have required significant computer resources and longer runtime. Based on previous model runs performed on domains (and restricted computational grids) of the size described in this report, it is expected that runtimes could increase by a factor for 4 to 5 with the inclusion of puff-splitting. Due to this, OG&E evaluated the use of this option during the modeling analysis and provide details in the modeling report about its use.

The modeling was conducted using the CENRAP recommended parameters, except the ones listed below. A explanation is also provided as to why the CENRAP recommended parameters were not used for these variables.

CALPUFF Input Variables Where CENRAP Suggested Value was not Used

Variable	Suggested	Used	Description	Reason
NSE	8	6	# Chemical Species to be emitted	SOA and EC not included
MSPLIT	0	1	Puff splitting	Allowed for puff splitting due to distances
DGRIDKM	6.0	3.0	Grid Spacing (km)	Refined Grid Spacing
NH_3	8.0E-5	NA	Scavenging Coefficient for liquid precipitation (s^{-1})	
	0	NA	Scavenging Coefficient for frozen precipitation (s^{-1})	
MH2O2	1	0	Background H2O2 Concentrations	Need to chose 0 to use monthly background value
BCKH2O2	1	12*1	Background Monthly H2O2 Concentrations	
OFRAC	0.2	0.15, 0.15, 0.2, 0.2, 0.2, 0.2, 0.2, 0.2, 0.2, 0.2, 0.2, 0.15	Organic Fraction for SOA option	Irrelevant MCHEM ≠ 4
IPTU	1	3	Units for Point Source emissions	Used lb/hr

CALPOST

A three-year CALPOST analysis was conducted to determine the visibility change in deciview (dv) caused by OG&E's BART-eligible sources when compared to a natural background.

Light Extinction Algorithm

EPA's currently approved algorithm for reconstructing light extinction (as opposed to the new equation for reconstructing light extinction recommended by the IMPROVE Steering Committee) was used. The background extinction coefficient b_{ext}, background is affected by various chemical species and the Rayleigh scattering phenomenon. The light extinction equation is provided below.

$$b_{ext} = 3*f(RH)*[(NH_4)_2SO_4] + 3*f(RH)*[NH_4NO_3] + 4*[OC] + 1*[PM_F] + 0.6*[PM_C] + 10*[EC] + b_{Ray}$$

The algorithm was used to calculate the daily light extinction attributable to the Seminole Station's BART eligible sources and light extinction attributable to a natural background. The change in deciviews based on the source and background light extinctions was evaluated using the equation below.

$$\Delta\ dv = 1\ 0 *\ln[(b_{ext,\ background} + b_{ext,\ source})/b_{ext,\ background}]$$

CALPOST Processing Method

CALPOST Method 6, which calculates hourly light extinction impacts for the source and background using monthly average relative humidity adjustment factors was used in the refined BART analysis. Monthly Class I Area-specific relative humidity adjustment factors based on the centroid of the Class I Areas as included in Table A-3 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program* were used.

Monthly Humidity Factors

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek	3.4	3.1	2.9	3.0	3.6	3.6	3.4	3.4	3.6	3.5	3.4	3.5
Hercules-Glades	3.2	2.9	2.7	2.7	3.3	3.3	3.3	3.3	3.4	3.1	3.1	3.3
Upper Buffalo	3.3	3.0	2.7	2.8	3.4	3.4	3.4	3.4	3.6	3.3	3.2	3.3
Wichita Mountains	2.7	2.6	2.4	2.4	3.0	2.7	2.3	2.5	2.9	2.6	2.7	2.8

Natural Background

EPA's default average annual aerosol concentrations for the U.S. that are included in Table 2-1 of EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program* were used.

Default Average Annual Natural Background Levels

Class I Area	Region	SO_4	NO_3	OC	EC	Soil	Coarse Mass
Caney Creek	WEST	0.12	0.10	0.47	0.02	0.50	3.00
Hercules-Glades	EAST	0.23	0.10	1.40	0.02	0.50	3.00
Upper Buffalo	EAST	0.23	0.10	1.40	0.02	0.50	3.00
Wichita Mountains	WEST	0.12	0.10	0.47	0.02	0.50	3.00

Evaluating Visibility Results

~~Trinity compared~~A comparison of ~~the~~ high ~~of the~~ 2001 through 2003 daily Δ dv values output by CALPOST to a contribution threshold of 0.5 Δ dv. Since the 98th percentile Δ dv values (the 7th highest value, 22nd highest over three years) output by CALPOST was greater than 0.5 Δ dv, the source was subject to BART regulations and submitted their BART determination to AQD.

Summary of CALPOST Control Parameters

A listing of the CALPOST parameters ~~that Trinity~~ used in OG&E's modeling analysis is referenced in the table below. In cases where a parameter to be used is different than what CENRAP recommended, a short explanation as to the difference is provided.

CALPUFF Input Variables Where CENRAP Suggested Value was not Used

Variable	Suggested	Used	Description	Reason
BEXTBTBK	12	NA	Background Extinction for MVISBK=1	Not necessary since MVISBK=6
RHFRAC	10	NA	% of Particles affected by RH	Not necessary since MVISBK=6

SECTION VII. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application and listed in OAC 252:100-8, Appendix I, are listed below. Recordkeeping for activities indicated with "*" is listed in the Specific Conditions.

* Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power or for peaking power service not exceeding 500 hours/year. There is one rarely-used 20,150kW emergency generator.

* Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period. One 1,500-gallon gasoline tank is located on-site and records are kept which demonstrate the facility uses much less than the 2,175 gallons/day.

* Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature. There is one 550 gallon vehicle diesel storage tank on site.

Cold degreasing operations utilizing solvents that are denser than air. Cold degreasing occurs in the maintenance shop.

Hazardous waste and hazardous materials drum staging areas. The facility stores used oil and used solvent in the machine shop and in the basement between Units 1 and 2. Used antifreeze is stored in the garage building.

Sanitary sewage collection and treatment facilities other than incinerators and Publicly Owned Treatment Works (POTW). Stacks or vents for sanitary sewer plumbing traps are also included (i.e., lift station). The facility operates a sanitary sewage collection and treatment facility.

Surface coating and degreasing operations which do not exceed a combined total usage of more than 60 gallons/month of coatings, thinners, clean-up solvents, and degreasing solvents at any one emissions unit. The facility conducts surface coating and degreasing operations in the maintenance shop. Maintenance is a listed "trivial activity," therefore, no recordkeeping will be required.

Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas. The facility maintains exhaust systems for the environmental laboratory.

Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas. The facility performs small amounts of hand wiping and spraying of solvents.

* Activities that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant. This covers the auxiliary boiler and fuel oil storage tanks; records of throughput and calculated emissions will be required.

SECTION VIII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the operating permit application, or developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies limits for fuel-burning equipment particulate emissions based on heat input capacity. Emissions limitations and anticipated emissions are shown in the following table. Emissions listed for the boilers are based on the allowable emissions. All units are in compliance with this subchapter.

			SC 19 Limit	Calculated Emissions, lb/hr	
EU	**Description**	**MMBTUH**	**lb/hr**	**Scenario I**	**Scenario II**
2B-01	Unit 1 boiler	5,480	656.77	41.65	41.65
2B-02	Unit 2 boiler	5,480	656.77	41.65	41.65
2B-03	Unit 3 boiler	5,496 gas 3,681 oil	658.11 gas 497.31 oil	41.77	487.94
3B-01	Gas turbine	300	80.24	1.98	1.98
3B-02	Aux boiler	33.47	15.11	0.25	0.25

AP-42 (7/1998), Section 1.4 lists the total PM emissions for natural gas to be 0.0076 lb/MMBTU.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas, there is very little possibility of exceeding the opacity standards. When burning fuel oil, the permit will require either using a continuous opacity monitor (COMS) or Method 22 and then Method 9 if visible emissions are detected. The permit will also include reduced visible emission observation requirements when burning fuel oil if no visible emissions are detected or if visible emissions observations using Method 9 are below the 20 % opacity limitation.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 3 establishes short-term ambient standards for SO_2. Air dispersion modeling of Unit 3 was conducted burning 24,521 gal/hr of No. 6 fuel oil with a sulfur content of 1.65% by weight. Results of the modeling are tabulated following. All ambient SO_2 impacts are in compliance with the limitations of Subchapter 31.

SO_2 Ambient Impacts

Averaging Time	SC 31 Limits, $\mu g/m^3$	Maximum Impacts, $\mu g/m^3$
1-hour	1,200	792
3-hours	650	318
24-hours	130	100
Annual	80	4

Part 5 limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). All of the fuel-burning equipment at this facility was constructed prior to the applicability date.

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]
This subchapter limits NO_X emissions from new fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH. All of the emission units that exceed the 50 MMBTUH threshold are considered existing emission units.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 24, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The facility includes a 1,500-gallon gasoline tank installed in 1992, which is subject to the submerged fill requirement. The fuel oil storage tanks, emergency generator fuel tank, and diesel vehicle fuel tank are not subject since they do not store a VOC with a vapor pressure greater than 1.5 psia.
Part 3 requires loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. This facility does not load tanks with a capacity greater than 200 gallons. Therefore, this requirement is not applicable.
Part 5 limits the VOC content of coatings used in coating lines or operations of parts and products. Any painting operation will involve maintenance coatings of buildings and equipment and emit less than 100 pounds per day of VOC and so is exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained,

and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-7	Minor Facility Permits	not in source category
OAC 252:100-11	Alternative Reduction Plans	not eligible
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-35	Carbon Monoxide	not in source category
OAC 252:100-39	Nonattainment Areas	not in a subject area
OAC 252:100-47	Landfills	not type of emission unit

SECTION IX. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Not Applicable]

Emissions of several regulated pollutants exceed 100 TPY, the level at which PSD defines the facility to be a major source. Any future expansion must be evaluated in the context of PSD significance levels (100 TPY CO, 40 TPY NO_x, 40 TPY SO_2, 40 TPY VOC, 25 TPY PM, 15 TPY PM_{10}, or 0.6 TPY lead). The permit will require the facility to apply for and obtain a PSD construction permit prior to modification of the boilers if the modifications will result in a significant emission increase and a significant net emission increase of a regulated NSR pollutant.

NSPS, 40 CFR Part 60 [Not Applicable]

Subpart D, Fossil-Fuel-Fired Steam Generators. This subpart is applicable to steam generating units constructed after August 17, 1971, which have a capacity greater than 250 MMBTUH heat input. Boilers No. 1, 2, and 3 commenced construction prior to August 17, 1971. The definition of steam generating unit is limited to furnaces or boilers.

Subpart Da, Electric Utility Steam Generating Units. This subpart is applicable to steam generating units constructed, reconstructed, or modified after September 18, 1978, which have a capacity greater than 250 MMBTUH heat input. Boilers No. 1, 2, and 3 and Turbine No. 1 have not been modified or reconstructed after September 18, 1978 and are not subject to this subpart.

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units which were constructed, reconstructed, or modified after June 19, 1984, but on or before June 19, 1986, and which have a heat input capacity of 100 MMBTUH or more. All of the steam generating units were constructed prior to June 19, 1984 and have not been reconstructed or modified.

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units constructed after June 9, 1989, and with capacity between 10 and 100 MMBTUH. The 33.47 MMBTUH steam generating unit was constructed prior to June 9, 1989, and is not subject to this subpart.
Subpart K, Petroleum Liquid Storage Vessels. This subpart affects petroleum liquid storage vessels with a capacity greater than 40,000 gallons and that commence construction or modification after June 11, 1973, and prior to May 19, 1978. The fuel oil tanks were installed prior to June 11, 1973.
Subpart Kb, VOL Storage Vessels. This subpart affects VOL storage vessels with a capacity greater than or equal to 19,813-gallons that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. The gasoline tank is below the 19,813-gallon threshold for this subpart.
Subpart GG, Stationary Gas Turbines. This subpart affects combustion turbines which commenced construction, reconstruction, or modification after October 3, 1977, and which have a heat input rating of 10 MMBTUH or more. The combustion turbine was constructed prior to the effective date of Subpart GG.
Subpart KKKK, Stationary Gas Turbines. This subpart affects stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005. The combustion turbine was constructed prior to the effective date of this subpart.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, mercury, coke oven emissions, radionuclides or vinyl chloride.

NESHAP, 40 CFR Part 63 [Subpart DDDDD Is Applicable]
Subpart Q, Industrial Cooling Towers. This subpart applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources as defined in § 63.401. This facility does not have or use industrial process cooling towers that are operated with chromium-based water treatment chemicals.
Subpart YYYY, Stationary Combustion Turbines. This subpart affects any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions. The turbine located at this facility is considered an existing turbine since it commenced construction before January 14, 2003. Per § 63.6090(b)(4), existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part.
Subpart DDDDD, Industrial Boilers and Process Heaters. Subpart DDDDD regulated HAP emissions from industrial boilers and process heaters. In March, 2007, the EPA filed a motion to vacate and remand this rule back to the agency. The rule was vacated by court order, subject to appeal, on June 8, 2007. No appeals were made and the rule was vacated on July 30, 2007. Existing and new small gaseous fuel boilers and process heaters (< 10 MMBTUH heat rating) were not subject to any standards, recordkeeping, or notifications under Subpart DDDDD.

EPA is planning on issuing guidance (or a rule) on what actions applicants and permitting authorities should take regarding MACT determinations under either Section112(g) or Section 112(j) for sources that were affected sources under Subpart DDDDD and other vacated MACT. It is expected that the guidance (or rule) will establish a new timeline for submission of section 112(j) applications for vacated MACT standards. Until such time as more guidance is received, AQD has determined that a 112(j) determination is not needed for sources potentially subject to a vacated MACT, including Subpart DDDDD. This permit may be reopened to address Section 112(j) when necessary.

CAM, 40 CFR Part 64 [Not Applicable]
Compliance Assurance Monitoring (CAM) applies to any pollutant specific EU at a major source, that is required to obtain a Part 70 operating permit, if it meets all of the following criteria:

1. It is subject to an emission limit or standard for an applicable regulated air pollutant;
2. It uses a control device to achieve compliance with the applicable emission limit or standard; and
3. It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source thresholds.

The requirements of this part do not apply to any of the following emission limitations or standards:

1. Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act; and
2. Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act.
3. Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in § 64.1.

In addition, the boilers do not use control devices to achieve compliance with an applicable emission limit.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility does not store any regulated substance above the applicable threshold limits. More information on this federal program is available at the web site: http://www.epa.gov/ceppo/.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
Acid Rain Permit No. 2004-186-ARR was issued on November 4, 2004, and remains in effect.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
SO_2 initial allowances as published in 40 CFR 73.10 are listed in Acid Rain Permit No. 96-285-AR. However, allowances can be traded, bought, and sold. Therefore, the actual allowances held by an affected unit may change which will not necessitate a revision to the permit.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
Certification testing has been completed for the CEM system required for each unit, and the EPA has issued approval of certification on September 22, 1997, for all three boilers.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The standard conditions of the permit address the requirements specified at § 82.156 for persons opening appliances for maintenance, service, repair, or disposal; § 82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; § 82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; § 82.166 for recordkeeping; § 82.158 for leak repair requirements; and § 82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

SECTION X. COMPLIANCE

Tier Classification and Public Review
This application has been determined to be Tier II based on the request for a significant modification of a Part 70 operating permit. The applicant has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the real property.

The applicant published the "Notice of Filing a Tier II Application" in the *Newspaper*, a daily newspaper, in Seminole County, on DATE. The notice stated that the application was available for public review LOCATION. The applicant will publish the "Notice of Tier II Draft Permit" in the *Newspaper*, a daily newspaper, in Seminole County. This facility is not located within 50 miles of the Oklahoma border. The draft permit will also be available for pubic review on the Air Quality section of the DEQ Web Page: *http://www.deq.state.ok.us/*.

Information on all permit actions is available for review in the Air Quality section of the DEQ Web page: *http://www.deq.state.ok.us/*.

Inspection
A full compliance evaluation inspection was conducted on March 9, 2005. Mr. Jason Lipscomb of Air Quality who was accompanied by Ms. Melody Martin, Staff Chemist, conducted the inspection. The facility was physically as described in the permit application and supplemental materials. No violations were noted during the inspection.

Fees Paid
Significant modification of a Part 70 source operating permit application fee of $1,000.

SECTION XI. SUMMARY

The facility was constructed and is operating as described in the permit application. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues concerning this facility. Issuance of the modified operating permit is recommended, contingent on EPA and public review.

DRAFT

PERMIT TO OPERATE
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Oklahoma Gas & Electric Company
Seminole Generating Station **Permit No. 2003-400-TVR (M-1)**

The permittee is authorized to operate in conformity with the specifications submitted to Air Quality on December 19, 2003, July 22, 2005, and March 30, 2007, and all supplemental information. The Evaluation Memorandum dated October 27, 2009, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emissions limitations for each point: [OAC 252:100-8-6(a)]

All units in **EUG 2, EUG 3** and **EUG 4** are "grandfathered" (pre-October 1972 construction) or are an "insignificant activity." There are no hourly or annual emission limits applied to the following units under Part 70, but they are limited to the equipment as is.

Point	Manufacturer	MMBTUH	kW	Serial Number
2-B-01	Babcock & Wilcox El-Paso	5,480	509,719	BW-22731
2-B-02	Babcock & Wilcox El-Paso	5,480	504,604	BW-22826
2-B-03	Babcock & Wilcox El-Paso	5,496	505,980	BW-23416
4-B-01	General Electric	300	20,150	179530
3-B-02	Cleaver-Brooks	33.47	N/A	L-58163

a. The permittee shall either monitor the opacity of discharges using a continuous opacity monitor or conduct daily visual observations. If a daily visual observation is the method of choice, then an EPA Reference Method 22 shall be conducted while burning No. 2 or No. 6 fuel oil for more than 24 continuous hours and records kept of these observations. If visible emissions are detected, then the permittee shall conduct a thirty-minute opacity reading in accordance with EPA Reference Method No. 9.
   i. If a Method 9 observation exceeds 20% opacity the permittee shall conduct at least two additional Method 9 observations within the next 24-hours.
   ii. If more than one six-minute Method 9 observation exceeds 20% opacity in any consecutive 60 minutes; or more than three six-minute Method 9 observations in any consecutive 24 hours exceeds 20% opacity; or if any six-minute Method 9 observation exceeds 60% opacity; the owner or operator shall comply with the provisions for excess emissions in OAC 252:100-9. [OAC 252:100-25]

b. The permittee shall be authorized to utilize natural gas as the primary fuel. Fuel oil (#2 or #6) may be utilized as a secondary fuel in Unit 2-B-03. A permit modification shall be required to burn fuel oil in Units 1 and 2 dependent on a demonstration of compliance with OAC 252:100-31. [OAC 252:100-31]

c. Boilers ~~S~~2-B-01, 2-B-02, and 2-B-03 are authorized to combust non-hazardous waste on an as-needed basis, generated on-site, from other OG&E facilities, or from OG&E employees and retired employees. The waste combusted may include, but is not limited to, used oil, EH fluid and used antifreeze. [OAC 252:100-31]

d. Fuel oil may be burned in only Unit 3. Residual fuel oil shall contain no more than 1.65% by weight sulfur and distillate fuel oil shall contain no more than 1.84% by weight sulfur. [OAC 252:100-31]

EUG 5 (Storage Tanks): VOC emissions from storage tanks are insignificant based on existing equipment items and do not have a specific limitation.

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

a. Gasoline Tank 5-B-05 shall be operated with a submerged fill pipe.[OAC 252:100-37]

2. The permittee shall be authorized to operate the facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

3. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following: [40 CFR Part 72, 73, and 75]

a. SO_2 allowances.
b. Report quarterly emissions to EPA.
c. Conduct RATA tests.
d. QA/QC plan for maintenance of the CEMS.

4. The following records shall be maintained on-site. All such records shall be made available to regulatory personnel upon request. These records shall be maintained for a period of at least five years after the time they are made. [OAC 252:100-8-6 (a)(3)(B)]

a. Quantity of each type of fuel and other materials burned (monthly).
b. Emissions data as required by the Acid Rain Program.
c. RATA test results from periodic CEMS quality assurance tests.
d. Operating hours for each boiler.

e. Date and time of visual emission observations (Method 22 of 40 CFR Part 60) when burning fuel oil, stack or emission point observed, operational status of the emission unit, observed results and conclusions, and any required Reference Method No. 9 results; or continuous opacity monitor results if used instead of visual monitoring.
f. Sulfur content of fuels per 40 CFR Part 75.

5. No later than 30 days after each anniversary date of the issuance of the original permit (June 21, 1999), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit.
[OAC 252:100-8-6 (c)(5)(a)&(d)]

6. The following records shall be maintained on-site to verify insignificant activities.
[OAC 252:8-6(a)(3)(b)]

a. Fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period: capacity of the tanks and the amount of throughput (annual).
b. Fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: capacity of the tanks and contents.
c. Activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions from that activity (annual).

7. The permittee shall have the discretion of determining which records will be maintained in digital format.

8. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility.
[OAC 252:100-8-6(d)(2)]

a. OAC 252:100-11 Alternative Emissions Reduction
b. OAC 252:100-15 Mobile Sources
c. OAC 252:100-17 Incinerators
d. OAC 252:100-23 Cotton Gins
e. OAC 252:100-24 Grain elevators
f. OAC 252:100-33 NO_X
g. OAC 252:100-35 Carbon Monoxide
h. OAC 252:100-39 Organic Materials
i. OAC 252:100-47 Landfills

9. This permit supersedes all previous Air Quality permits for this facility, except Acid Rain Permit No. 2004-186-ARR, which are now null and void.

10. Boiler 3-B-02 (the auxiliary boiler) is subject to NESHAP, Subpart DDDDD with a compliance date of September 13, 2007. As of that date, the permittee shall comply with all applicable provisions. [40 CFR Part 63, Subpart DDDDD]

11. The boilers in EUG 2 are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including but not limited to the following: [40 CFR §§ 51.300-309 & Part 51, Appendix Y]

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

EU ID#	Point ID#	EU Name	Heat Capacity (MMBTUH)	Construction Date
2-B	01	Unit 1 Boiler	5,480	1968
2-B	02	Unit 2 Boiler	5,480	1968
2-B	03	Unit 3 Boiler	5,496	5/28/70

b. Each existing affected facility shall install and operate the ~~SIP approved BART as expeditiously as practicable but in~~ equipment listed in Specific Condition 11.d. no later than five years after USEPA approval of the SIP incorporating the BART requirements or final resolution to any BART related legal action whichever is later.

c. The permittee shall apply for and obtain a construction permit prior to modification of the boilers~~. I~~ if the modifications result in an increase in any air pollutant or results in the emissions of any air pollutant not previously emitted. If the modification will ~~result in~~cause a significant emission increase and a significant net emission increase of a regulated NSR pollutant, the applicant shall apply for a PSD construction permit.

d. The affected facilities shall be equipped with the following current combustion control technology, as determined in the submitted BART analysis, to reduce emissions of NO_X to below the emission limits below:
   i. Low-NO_X Burners,
   ii. Overfire Air, and
   iii. Flue Gas Recirculation.
   Note that Seminole Unit3 is currently designed with FGR.

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e. The permittee shall maintain the combustion controls (Low-NO_X burners, overfire air, and flue gas recirculation) and establish procedures to ensure the controls are properly operated and maintained.

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

EU ID#	Point ID#	NO_X Emission Limit	Averaging Period
2-B	01	0.203 lb/MMBTU	30-day rolling
2-B	02	0.212 lb/MMBTU	30-day rolling
2-B	03	0.164 lb/MMBTU	30-day rolling

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

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

i. Within 60 days of achieving ~~achieving~~ the maximum production rate at which the affected facilities will be operated, after modification of the boilers, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities. [OAC 252:100-8-6(a)]

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

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

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

   Method 1: Sample and Velocity Traverses for Stationary Sources.

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

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

   Method 4: Determination of Moisture in Stack Gases.

   Method 10: Determination of Carbon Monoxide Emissions from Stationary Sources.

   Method 6C: Quality Assurance Procedures (Range and Sensitivity, Measurement System Performance Specification, and Measurement System Performance Test Procedures) shall be used in conducting Method 10.

   Method 20: Determination of Nitrogen Oxides and Oxygen Emissions from Stationary Gas Turbines.

   Method 25/25A: Determination of Non-Methane Organic Emissions From Stationary Sources.

Comment [A8]: If the BART emission limit is for NOx are we required to test for CO and VOC?

Comment [A9]: Method 10 references method 7e unsure why 6C is required instead?

Oklahoma Gas & Electric
Attn: David Branecky
Environmental Administrator
P. O. Box 321
Oklahoma City, OK 73101

Re: Permit Application No. **2003-400-TVR (M-1)**
Seminole Generating Station
Seminole County, Oklahoma

Dear Mr. Branecky:

Air Quality has received the permit application for the referenced facility and completed initial review. This application has been determined to be a Tier II application. In accordance with 27A O.S. 2-14-301 and 302 and OAC 252:4-7-13(c) the application and enclosed draft permit are now ready for public review. The requirements for public review of the draft permit include the following steps, which you must accomplish:

1. Publish at least one legal notice for the draft permit (one day) in at least one newspaper of general circulation within the county where the facility is located. (Instructions enclosed)
2. Provide for public review (for a period of 30 days following the date of the newspaper announcement) a copy of the draft permit at a convenient location (preferentially at a public location) within the county of the facility.
3. Send AQD a written affidavit of publication for the notice from Item #1 above together with any additional comments or requested changes, which you may have for the permit application within 20 days of publication.

The permit review time is hereby tolled pending the receipt of the affidavit of publication. Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact the permit writer at eric.milligan@deq.ok.gov or at (405) 702-4217.

Sincerely,

Phillip Fielder, P.E.
Permits and Engineering Group Manager
AIR QUALITY DIVISION

Enclosures

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON STREET, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2003-400-TVR (M-1)

Oklahoma Gas & Electric

having complied with the requirements of the law, is hereby granted permission to operate the Seminole Generating Station, Section 25, T6N, R5E, Seminole County, Oklahoma, subject to the Standard Conditions dated July 21, 2009, and Specific Conditions, both of which are attached.

This permit shall expire May 9, 2011, except as Authorized under Section VIII of the Standard Conditions.

Division Director, Air Quality Division **Date**

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1)the date, place and time of sampling or measurement;
(2)the date or dates analyses were performed;
(3)the company or entity which performed the analyses;
(4)the analytical techniques or methods used;
(5)the results of such analyses; and
(6)the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants

("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or

intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.

[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby. [OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege. [OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit. [OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.
[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.
[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.
[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;

(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of

adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be

certified by an approved technician certification program pursuant to § 82.161;

(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;

(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and

(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.

(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).

(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 C.F.R. § 70.8(d).

(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]