OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **April 28, 2015**

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

THROUGH: Rick Groshong, Environmental Programs Manager, Enforcement Section

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

THROUGH: Peer Review

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

SUBJECT: Evaluation of Permit Application No. **2010-594-C (M-2) PSD**
Oklahoma Gas & Electric Company
Seminole Generating Station (4911)
Facility ID: 1210
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 construction permit to implement the controls and emission limits required by the Best Available Retrofit Technology (BART) program as incorporated into Permit No. 2003-400-TVR (M-1), issued June 27, 2011. The modifications include retrofitting all three boilers (Units 1, 2, & 3) with low NO_X combustion systems including Low-NO_X burners and overfire air systems and appurtenances necessary for proper operation. OG&E is also proposing to retrofit Units 1 and 2 with flue gas recirculation systems (FGR). Unit 3 is already equipped with FGR. Construction is expected to begin in the spring of 2015 with Unit 2, followed by Unit 1 in the spring of 2016, and Unit 3 in the spring of 2017. The facility is currently operating under Permit No. 2010-594-TVR2 (M-1) issued November 26, 2012. All three units are currently considered “grandfathered” and currently do not have specific emission limits established in the current permit. This permit will also establish that the current BART NO_X emission limits for each of the affected units are based on a 30-day rolling average in accordance with the BART submittal.

OG&E has also requested to replace the existing natural gas fired auxiliary boiler (EUG3). The existing “grandfathered” boiler was constructed in 1974 and is no longer operational. The replacement unit is similar in size and will be used for house heat at the facility. The new boiler is a natural gas fired 40.4 MMBTUH Cleaver-Brooks Model CBEX Elite.

SECTION II. FACILITY DESCRIPTION

The Seminole facility consists of three (3) natural gas fired 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. Unit 1, Unit 2, and Unit 3 use natural gas as their primary fuel and are limited to using #2 fuel oil as a secondary fuel during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel.

The facility utilizes a gas-fired auxiliary boiler. The boiler has a rated capacity of 40.4 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 emergency power generation at the plant. The gas turbine is a simple cycle, single shaft, two bearing, dual fired turbine capable of producing 20,150 kW of electricity. The facility also has two small emergency generators and an emergency fire water pump engine.

Two (2) mechanical dust collectors with inlet vanes, tubes, and hoppers were installed on Unit 3 to collect particulate matter and unburned carbon resulting from the combustion of #6 fuel oil. However, Unit 3 no longer combust #6 fuel oil. The dust 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 non-hazardous waste 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	Const. Date
None	None	Facility	1968 - 1970

EUG 2 Boilers

EU ID#	Point ID#	EU Name/Model	Heat Capacity (MMBTUH)	Const. Date
2-B	01	Unit 1 Boiler Babcock & Wilcox El Paso	5,480	1968
2-B	02	Unit 2 Boiler Babcock & Wilcox El Paso	5,480	1968
2-B	03	Unit 3 Boiler Babcock & Wilcox El Paso	5,496	5/28/70

EUG 3 Auxiliary Boiler

EU ID#	Point ID#	EU Name/Model	Heat Capacity (MMBTUH)	Const. Date
3-B	03	Auxiliary Boiler Cleaver-Brooks Model CBEX Elite	40.4	2015

EUG 4 Gas Turbine

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

EUG 5 Storage Tanks

EU ID#	Point ID#	EU Name/Model	Capacity (Gallons)	Inst. Date
5-B	05	Gasoline Tank	1,500	1992

EUG 6 Emergency Equipment

EU ID#	Point ID#	EU Name/Model	Serial #	Capacity (HP)	Const. Date
6-B	01	Emergency Generator Detroit Diesel 7123-7300	185A1417P1	300	1970
6-B	02	Emergency Fire Pump Detroit Diesel 6-71 RC-56	6A 01 90675	177	1970
6-B	03	Emergency Generator Generac QT025A	6215205	40	2011

Stack Parameters

Point	Height (ft)	Diameter (ft)	Flow (ACFM)	Temperature (°F)
2-B-01	178	15.0	1,471,810	247
2-B-02	178	15.0	1,471,810	247
2-B-03	350	18.0	1,549,381	282
3-B-03	52	2.0	14,060	430
4-B-01	25	10.8	482,264	895

SECTION IV. PSD REVIEW

Unit 1 Project Emission Increases (PEI)

	Heat Input	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2	CO_{2e}
EU	**MMBTU[6]**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
BAE[1, 2]	12,939,150	1,229.0	532.8	34.9	50.1	3.9	769,737
PAE[3]	12,956,500	1,315.1	3,012.4	34.9	48.3	3.8	770,768
PAE-BAE		86.1	2,479.6	0.0	-1.8	-0.1	1,031
AE[4]	25,658,268	3,181.7	1,056.5	69.2	95.6	7.7	1,526,390
PREI[5]	12,956,500		2,478.9				
PEI		**0.0**	**2,478.9**	**0.0**	**0.0**	**0.0**	**0.0**

1 - Baseline Actual Emissions are based on 24-month rolling annual average from 6/2011 to 5/2013 for all pollutants except for PM which are based on 12/2010 to 11/2012.

2 - BAE: NO_X, SO_2, & CO_2 emissions are based on CEM data; CO, VOC, and $PM_{10}/PM_{2.5}$ are based on AP-42 (7/1998), Section 1.4.

3 -.Projected Actual Emissions: NO_X emissions are based on BART limit of 0.203 lb/MMBTU; CO emissions are based on proposed BACT emission limit 0.465 lb/MMBTU; VOC, $PM_{10}/PM_{2.5}$, and SO_2 emissions are based on AP-42 (7/1998), Section 1.4; CO_2 emissions are based on 40 CFR Part 98, Appendix C default emission factors for NO_2 and CH_4 and global warming potentials and the average CO_2 emission factor (118.857 lb/MMBTU). The projected heat input was based on historical operation and an annual capacity factor of 27%.

4 - Accommodated Emissions: Emissions are based on the annualized highest monthly heat input and the BAE emission factors except for NO_2, SO_2, and CO_2 which are based on the annualized highest monthly CEM emissions from the baseline period.

5 - Project Related Emission Increases: Only emissions of CO are expected to increase as a result of this project. Therefore, CO emissions are based on the difference between the emission factors prior to the project (0.082 lb/MMBTU) and after the project (0.465 lb/MMBTU) and the projected actual heat input. Except for NO_2, the other emission factors remain the same or decrease. These emission increases which are a part of PAE cannot be excluded under AE.

Unit 2 PEI

	Heat Input	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2	CO_{2e}
EU	**MMBTU**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
BAE[1, 2]	12,388,906	1,288.4	510.1	34.9	47.1	3.7	736,998
PAE[3]	13,440,804	1,424.7	3,125.0	36.2	50.1	4.0	799,572
PAE-BAE		195.7	2,614.9	1.3	3.0	0.3	62,574
AE[4]	27,503,424	4,186.5	1,132.5	74.2	102.5	8.3	1,636,133
PREI[5]	13,440,804		2,571.5				
PEI		**0.0**	**2,571.5**	**0.0**	**0.0**	**0.0**	**0.0**

1 - Baseline Actual Emissions are based on 24-month rolling annual average from 6/2011 to 5/2013 for all pollutants except for PM which are based on 12/2010 to 11/2012.

2 - BAE: NO_X, SO_2, & CO_2 emissions are based on CEM data; CO, VOC, and $PM_{10}/PM_{2.5}$ are based on AP-42 (7/1998), Section 1.4.

3 -.Projected Actual Emissions: NO_X emissions are based on BART limit of 0.212 lb/MMBTU; CO emissions are based on proposed BACT emission limit 0.465 lb/MMBTU; VOC, $PM_{10}/PM_{2.5}$, and SO_2 emissions are based

on AP-42 (7/1998), Section 1.4; CO_2 emissions are based on 40 CFR Part 98, Appendix C default emission factors for NO_2 and CH_4 and global warming potentials and the average CO_2 emission factor (118.856 lb/MMBTU). The projected heat input was based on historical operation and an annual capacity factor of 28%.

4 - Accommodated Emissions: Emissions are based on the annualized highest monthly heat input and the BAE emission factors except for NO_2, SO_2, and CO_2 which are based on the annualized highest monthly CEM emissions from the baseline period.

5 - Project Related Emission Increases: Only emissions of CO are expected to increase as a result of this project. Therefore, CO emissions are based on the difference between the emission factors prior to the project (0.082 lb/MMBTU) and after the project (0.465 lb/MMBTU) and the projected actual heat input. Except for NO_2, the other emission factors remain the same or decrease. These emission increases which are a part of PAE cannot be excluded under AE.

Unit 3 PEI

	Heat Input	**NO_X**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SO_2**	**CO_{2e}**
EU	**MMBTU**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
BAE[1, 2]	13,129,955	1,110.4	540.6	35.4	44.7	3.9	781,089
PAE[3]	14,922,817	1,223.7	3,469.6	36.2	50.1	4.0	887,742
PAE-BAE		113.3	2,929.0	1.3	3.0	0.3	62,574
AE[4]	27,793,954	2,208.0	1,144.5	74.9	103.5	8.3	1,653,431
PREI[5]	14,922,817		2,855.1				
PEI		**0.0**	**2,855.1**	**0.0**	**0.0**	**0.0**	**0.0**

1 - Baseline Actual Emissions are based on 24-month rolling annual average from 6/2011 to 5/2013 for all pollutants except for PM which are based on 12/2010 to 11/2012.

2 - BAE: NO_X, SO_2, & CO_2 emissions are based on CEM data; CO, VOC, and $PM_{10}/PM_{2.5}$ are based on AP-42 (7/1998), Section 1.4.

3 -.Projected Actual Emissions: NO_X emissions are based on BART limit of 0.164 lb/MMBTU; CO emissions are based on proposed BACT emission limit 0.465 lb/MMBTU; VOC, $PM_{10}/PM_{2.5}$, and SO_2 emissions are based on AP-42 (7/1998), Section 1.4; CO_2 emissions are based on 40 CFR Part 98, Appendix C default emission factors for NO_2 and CH_4 and global warming potentials and the average CO_2 emission factor (118.857 lb/MMBTU). The projected heat input was based on historical operation and an annual capacity factor of 31%.

4 - Accommodated Emissions: Emissions are based on the annualized highest monthly heat input and the BAE emission factors except for NO_2, SO_2, and CO_2 which are based on the annualized highest monthly CEM emissions from the baseline period.

5 - Project Related Emission Increases: Only emissions of CO are expected to increase as a result of this project. Therefore, CO emissions are based on the difference between the emission factors prior to the project (0.082 lb/MMBTU) and after the project (0.465 lb/MMBTU) and the projected actual heat input. Except for NO_2, the other emission factors remain the same or decrease. These emission increases which are a part of PAE cannot be excluded under AE.

New Auxiliary Boiler PEI

	Heat Input	**NO_X**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SO_2**	**CO_{2e}**
EU	**MMBTU**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
BAE[1]	---	---	---	---	---	---	---
PAE[2]	125,240	2.2	0.5	0.3	0.5	0.04	7,450
PEI		**2.2**	**0.5**	**0.3**	**0.5**	**0.1**	**7,450**

[1] - Baseline Actual Emissions for new emission units are zero.

[2] - PAE: NO_X: 0.035 lb/MMBTU; CO: 0.0075 lb/MMBTU; SO_2, VOC, and $PM_{10}/PM_{2.5}$ are based on AP-42 (7/1998), Section 1.4. CO_2 emissions are based on 40 CFR Part 98, Appendix C default emission factors for NO_2 and CH_4 and global warming potentials and the average CO_2 emission factor (118.857 lb/MMBTU). The projected heat input was based on historical operation of the existing auxiliary boiler and an annual capacity factor of 35%.

Total Project Emission Increases (PEI)

	NO_X	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2	CO_{2e}
EU	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
Unit 1	---	2,478.9	---	---	---	---
Unit 2	---	2,571.5	---	---	---	---
Unit 3	---	2,855.1	---	---	---	---
Aux. Boiler	2.2	0.5	0.3	0.5	0.1	7,450
PEI	**2.2**	**7,906.0**	**0.3**	**0.5**	**0.1**	**7,450**

Projected actual emissions shall exclude, in calculating any increase in emissions that results from the particular project, that portion of a unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project. Capable of accommodating is interpreted to include historically demonstrated and credible capacities of a source's actual operation, or emissions, which occurred through the baseline period. It is possible, with credible justification, to exclude emissions that are unrelated to the project and that could have been accommodated during the baseline period. In a 2010 memo to Georgia Pacific Sawmill in the State of Mississippi, the EPA accepted the use of the highest demonstrated monthly operating level during the baseline period for use in calculating emissions that the source was physically capable of accommodating. Consistent with this approach, to estimate emissions that the source was physically capable of accommodating, OG&E has selected the highest monthly emission rate within the baseline period and used this rate to predict emissions that "could have been accommodated" and excluded these emissions from projected actual emissions to determine emissions attributable to the project.

NO_X emissions are expected to decrease on a lb/MMBTU basis due to the installation of Low-NO_X burners, although, the annual average CEM data values for NO_X are lower than the BART emission limits for Unit 1 and Unit 2. Emissions of VOC and $PM_{2.5}$ are expected to increase slightly on a lb/MMBTU basis due to lower combustion efficiencies. However, emission factors for boilers equipped with Low-NO_X burners are the same as the emission factors for boilers without Low-NO_X burners. Emissions of SO_2 are expected to remain the same on a lb/MMBTUH basis since the amount of sulfur in the fuel gas will not change. CO emissions on a lb/MMBTUH basis are expected to increase as a result of the modification.

To ensure that the CO emission increases that are related to the project are not excluded from the project emission increases (PAE-BAE) using the accommodated emissions (AE), project emission increases for CO are strictly based on the difference between the BAE and PAE heat input times the difference between the pre-project (0.082 lb/MMBTU) and post-project (0.465

lb/MMBTUH) emission factors. Project emission increases of CO are greater than the PSD significance levels. Therefore, this project is subject to PSD.

SECTION V. BACT REVIEW

Any major stationary source or major modification subject to PSD review must conduct an analysis to ensure the implementation of BACT. The requirement to conduct a BACT analysis is set forth in the federal PSD regulations (40 CFR 52.21), and in Oklahoma regulations. The State of Oklahoma defines BACT in OAC 252:100-8-31, as follows:

> "...means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant."

Although BACT is determined by evaluating control technologies to determine which are technically and economically feasible, BACT is an emission limit, not the use of a specific technology. A BACT analysis is required to assess the appropriate level of control for each new or physically modified emissions unit for each pollutant that exceeds an applicable PSD significant emission rate (SER). For the proposed Low-NO_X burners project at the Seminole facility, only CO emissions exceed the applicable PSD SER.

In a 1987 policy memorandum, EPA stated its preference for a top-down approach to BACT analyses. Under the top-down approach, the most stringent control available for a similar or identical source or source category is identified and a determination of feasibility is made. If the top level of control is determined to be infeasible because of technical, economic, environmental, or energy related reasons, then the next most stringent control option is evaluated. This process continues until the BACT level under consideration cannot be eliminated. Presented below are the five basic steps of a top-down BACT review procedure according to the *New Source Review Workshop Manual (Draft)*:

Step 1. *Identify all control technologies.* The first step in the BACT analysis is to identify all control technologies for each pollutant.

Step 2. *Eliminate technically infeasible options.* The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those that are clearly technically infeasible are eliminated. EPA states the following with regard to technical feasibility:

> "A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical and engineering principles,

that technical difficulties would preclude the successful use of the control option on the emissions unit under review."

Step 3. *Rank remaining control technologies by control effectiveness.* The control technologies are then ranked in order of effectiveness. If only one option remains or if all remaining options are equivalent, then ranking is not required.

Step 4. *Evaluate most effective controls and document results.* The remaining control technologies are evaluated on the basis of economic, energy, and environmental considerations.

Step 5. *Select BACT*. The first four steps involve the evaluation of control technologies, but the selection of BACT involves an evaluation of achievable emission rates. The selected BACT emission rate is enforced as a standard unless technological or economic limitations would make the imposition of an emission standard infeasible, in which case a design, equipment, work practice, or operational standard can be imposed.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing three core requirements, which the agency believes must be met by any BACT determination, irrespective of whether or not it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies (i.e., those which provide the "maximum degree of emissions reduction"). Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decision. Thirdly, in no event, shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61.

<u>Step 1: Identify All Control Technologies</u>

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

Potentially applicable emission control technologies were investigated using the U.S. EPA control technology database, reviewing recent ODEQ BACT determinations for similar facilities, and by using process knowledge and engineering experience. The RACT/BACT/LAER Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies that have been approved in PSD permits as BACT for numerous process units. Process units in the database are grouped into categories by industry. A search of the RBLC database was performed to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for natural gas-fired utility boilers. Potential control technologies identified for CO shown below.

Potential CO Control Technologies for Utility Boilers

Control Technology	Typical Temperature	Typical Flow Rate
Oxidation Catalyst	600 – 800 °F (≤ 1,250 °F)	700 – 50,000 SCFM
Good Design & Combustion Practices	NA	NA

Oxidation Catalysts
Typical CO oxidation catalysts utilize a platinum/vanadium catalyst that oxidizes CO (and hydrocarbon compounds) to CO_2 and water as the emission stream passes through the catalyst bed. The chemical process is a straight catalytic oxidation reaction requiring no reagent. The oxidation is carried out by the following overall reaction:

$$2CO + O_2 \leftrightarrow 2CO_2$$

CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700°F to 1,100°F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200°F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the boiler exhaust lateral distribution. It is important that the gas flow is evenly distributed across the catalyst and that proper operating temperature at base load design conditions is maintained.

A CO catalyst also will oxidize other species within the boiler exhaust. For example, sulfur in natural gas (fuel sulfur and mercaptans added as an odorant) is oxidized to gaseous SO_2 within the combustor, but is further oxidized to SO_3 across a catalyst (30% conversion is assumed). SO_3 will then be emitted and/or combined to form H_2SO_4 (sulfuric acid mist) from the exhaust stack. These sulfates condense in the gas stream or within the atmosphere as additional PM_{10} (and $PM_{2.5}$). Thus, an oxidation catalyst would reduce emissions of CO and to some extent VOC, but would increase emissions of PM_{10} and $PM_{2.5}$. Also, the increased backpressure of the catalyst bed would require additional fuel firing to produce the same amount of electricity output, resulting in associated emission increases in other criteria pollutants. According to the EPA's RBLC database, no application of catalytic oxidation is being used to control CO emissions from a gas-fired boiler.

Good Combustion Controls
As products of incomplete combustion, CO emissions are effectively controlled by ensuring the complete and efficient combustion of the fuel in the boilers. LNB and OFA are two forms of combustion control that have been combined in a single technology to reduce NO_X emissions from natural gas-fired boilers. Typically, LNB/OFA tends to inhibit complete combustion, which increases the emissions of CO. On the other hand, high combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions, but tend to increase formation of NO_X emissions. Therefore, in terms of combustion controls, the best control technology for CO emissions directly conflicts with the LNB/OFA's ability to reduce emissions of NO_X. Nonetheless, LNB burner manufacturers strive for the delicate balance of decreasing NO_X emissions while at the same time limiting formation of CO emissions, resulting

in good combustion control practices based on a boiler-specific and fuel-specific LNB/OFA burner design.

Step 2: Eliminate Technically Infeasible Options

The second step is to eliminate the technically infeasible control options from those identified in Step 1. A technically infeasible control option is one that has not been "demonstrated," or more specifically, a technology that has not been installed and operated successfully on a similar type unit of comparable size. A technology is considered "demonstrated" for a given unit based on its "availability" and "applicability." "Availability," in regards to a control technology, refers to a technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. "Applicability," in regards to control options, means an available control option that can reasonably be installed and operated on the unit type under consideration. The application of an oxidation catalyst to a natural gas-fired utility boiler presents many substantial challenges that render this control technology technically infeasible for further consideration as a control technology for CO emissions from these units. The primary technical challenge that renders an oxidation catalyst control technically infeasible is that oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications which is the case for Seminole's three units. Below is a comparison of the typical inlet flow rate and temperature required for an oxidation catalyst and the actual exhaust flow rates and temperatures of Seminole's three boilers.

Typical Specifications: Oxidation Catalyst vs. Seminole Boilers Operating Parameters

Oxidation Catalyst Requirements		**Unit 1**	**Unit 2**	**Unit 3**
Temperature	600-800 °F (≤ 1,250 °F)	247 °F	247 °F	304 °F
Flow Rate	700-50,000 SCFM	928,840 SCFM	928,840 SCFM	931,552 SCFM

As seen in the table above, the exhaust flow rates of each boiler is much higher than the typical inlet flow rate but more importantly the operating temperature is significantly lower than the inlet temperature needed. Since the outlet temperature of each boiler is less than the required oxidation catalyst minimum inlet temperature, it is reasonable to conclude that this control technology technically is infeasible. To further support this, a review of the RBLC database indicates that there is no record of an oxidation catalyst being used to control emissions of CO on a natural gas-boiler of comparable size. While the CO oxidation catalyst is eliminated from further consideration for the reasons stated above, good combustion controls are well demonstrated and available, and thus considered technically feasible for the control of CO emissions.

<u>Step 3: Rank Remaining Control Technologies by Effectiveness</u>
The third step is to rank all the remaining control alternatives not eliminated in Step 2 based on their control effectiveness for the pollutant under review. In this step, the feasible technologies are reviewed in order to determine the control effectiveness on either a percent removal basis or emission level, or both, based on an engineering analysis and document review of the technology applied to similar units. The following informational databases, clearinghouses, and documents were used to identify recent control technology determinations for similar source categories and emission units:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC).
- PSD construction permit for Public Service Company of Oklahoma (PSO) – Southwestern Power Station7

<u>RBLC Results</u>
A search of the information contained in the RBLC was conducted to determine the top level of CO emission control for natural gas-fired boilers. Results were limited for large natural gas-fired boilers and are shown below. Nevertheless, the RBLC results indicate that good combustion controls is the top control for CO emissions from natural gas-fired utility boilers.

RBLC Results for CO BACT Analysis

RBLC ID	Facility	Issued Date	Process Description	Limitation	Control Method
LA-0227	Cleco Rodemacher Power Station	05/08/2008	Unit 2 Boiler (1-74), Natural Gas	3,000 lb/hr (0.55 lb/MMBTU)	LNB/OFA, Good Combustion
FL-0334	FL Power Anclote Power Station	9/14/2012	Unit 1 & Unit 2 5,500 MMBTUH	0.15 lb/MMBTU 30-day Avg.	OFA, Good Combustion

<u>PSO Southwestern - Permit Review</u>
A review of the PSO Southwestern Generating Station (PSO SW), issued by ODEQ on March 31, 2014, was conducted. The permitted project at the PSO SW facility was to install LNB/OFA on Unit 3 a 3,290 MMBTUH natural gas-fired boiler. PSO SW originally proposed a CO BACT emission limit of 0.15 lb/MMBTU. After installation of the LNB/OFA system and as authorized by AQD (Permit No. 2011-228-C (M-2) PSD issued on March 31, 2014), the CO BACT limit was changed to 0.465 lb/MMBTU based on a 30-day rolling average. This emission limit was based on the highest 1-hour average emission rate plus a 25% safety factor.

<u>Step 4: Evaluate Most Effective Controls and Document Results</u>
Additional evaluations are performed to consider and compare the energy, environmental, and economic impacts associated with implementing the viable control alternatives. The energy impact evaluation considers the energy penalty or benefit resulting from the operation of the control technology at the facility. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path.

The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which ultimately affects the cost-effectiveness of the control technology.

The environmental impact evaluation considers the collateral environmental effects resulting from the operation of each viable control alternative. Example environmental impacts may include additional water discharge and consumption, collateral emission increases, as well as disposable solids and waste generation. As previously discussed, the typical good combustion measures taken to minimize the formation of CO emissions, namely higher combustion temperatures, additional excess air, and optimum air/fuel mixing during combustion, are often counterproductive to the control of NO_X emissions. A proper balance of this phenomenon is a necessary task in obtaining and complying with the manufacturer's guarantees, since overly aggressive CO emission limits can jeopardize NO_X emissions design considerations. The third and final impact analysis addresses the economics of the proposed control technologies in order to evaluate and compare two or more alternatives. Since there is only one feasible control technology to limit the emissions of CO, a comparative cost analysis is not applicable.

Step 5: Select BACT

The highest ranked control technology from Step 3 that is not eliminated in Step 4 based on unacceptable economic, energy, or environmental impacts, is proposed as BACT for the pollutant and emission unit under review. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site- and/or project-specific consideration of the aforementioned screening criteria (e.g., technical, energy, environmental, and economic considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration. BACT cannot be determined to be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS) for the affected emission sources. However, there are no CO emission limits in NSPS for large boilers.

Based on the preceding BACT analysis, OG&E proposes good combustion practices as the only feasible control. The proposed BACT for CO is good combustion controls to achieve an emission limit of 0.465 lb/MMBTU based on a 30-day rolling average.

CO BACT

Pollutant	Control Technology	Limit
CO	Good Combustion Practices	0.465 lb/MMBTU

A shortened BACT review was conducted for the 40.4 MMBTUH Auxiliary Boiler. The selected BACT is shown below.

CO BACT

Pollutant	Control Technology	Limit
CO	Good Combustion Practices	0.0075 lb/MMBTU

SECTION VI. AIR DISPERSION MODELING REVIEW

As a result of the installation of LNB and FGR controls, expected emissions increases of CO will exceed the PSD SER. Therefore, OG&E must demonstrate that the increase in CO emissions from the Seminole facility do not cause a violation of the CO 1-hour and 8-hour National Ambient Air Quality Standards (NAAQS). The modeling analysis indicates that CO emissions from the Seminole facility do not cause or contribute to a modeled violation of the applicable CO 1-hour or 8-hour NAAQS.

Modeling Methodology

The goal of the air quality analysis is to demonstrate that the CO emissions from the OG&E Seminole facility do not cause or contribute to a violation of the NAAQS. Per EPA guidance, this is accomplished with a two-step air dispersion modeling analyses: significant impact analysis and full impact analysis. The significant impact analysis considers only the emissions associated with the proposed project to determine if it will have a significant impact on the surrounding area. A full impact analysis is performed, if necessary, based on the results of the significance analysis. The full impact analysis generally consists of two demonstrations: one that compares modeled results to the NAAQS and one that compares modeled results to any applicable PSD increments. However, there is no established increment for CO.

Significant Impact Analysis

In a significant impact analysis, the project-related emissions increase is modeled and the maximum modeled ground level concentration is compared to the corresponding significant impact level (SIL). The EPA requires that a full impact analysis be conducted if the project emissions result in maximum predicted concentrations exceeding a SIL. In addition, the permitting agency has the authority to exempt a project from pre-construction monitoring if the concentrations modeled in the significant impact analysis are less than the significant monitoring concentration (SMC). The SIL, SMC, and NAAQS for CO are shown below.

SIL, MDM, and NAAQS for CO

Pollutant	Avg. Period	SIL (μg/m^3)	SMC (μg/m^3)	NAAQS (μg/m^3)
CO	8-hour	500	575	10,000
	1-hour	2,000	--	40,000

Significant receptors for both averaging period analyses were determined by comparing the maximum modeled value for each receptor for each year in the modeled 5-year period to the appropriate SIL. If the highest modeled concentrations (highest first high) for CO in the significant impact analysis are less than the respective SIL, then further analyses are not required. If, however, modeled impacts are greater than a SIL, a full impact analysis is required to demonstrate that the facility does not cause or contributes to any exceedances of the NAAQS. As indicated below the model results for the 8-hour averaging period were above the SIL and SMC. Thus, a full impact analysis was required.

Dispersion Model Selection

Trinity used AERMOD PRIME, version 14134, and its associated pre-processors for the modeling analysis. The modeling analysis was performed using the regulatory default model settings, which include stack height adjusted for stack-tip downwash and missing data processing.

Terrain

Elevations for sources, buildings, and receptors were obtained using the National Elevation Dataset (NED), the primary elevation data product of United States Geological Survey (USGS). The NED data was processed with the AERMAP terrain preprocessor (version 11103).

Building Wake Effect (Downwash)

In order to account for building wake effects, direction-specific building dimensions used as input to the model were calculated using the algorithms of the EPA-sanctioned Building Profile Input Program-Plume Rise Model Enhancement (BPIP-PRIME). BPIP-PRIME is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, and the Building Downwash Guidance document while incorporating the enhancements to improve prediction of ambient impacts in building cavities and wake regions.

Meteorological Data

The meteorological data was previously provided and approved for use by ODEQ for another modeling analysis conducted for Seminole. The model runs were performed using 2006-2010 surface data from the Ada Oklahoma Mesonet Site (ADAX) and the ISH Ada Station (KADH) and upper air (UA) data from Norman, OK (OUN). The Mesonet data was provided to the Air Quality Division of ODEQ as a courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University and the University of Oklahoma.

Receptor Grid

The receptor grids used in this analysis reflect ODEQ’s current guidance. Ground-level concentrations are calculated for receptors located on five Cartesian grids covering a region that extends 10 km from all edges of the facility fence line. The grids are defined as follows:

- A fence line grid containing 50 meter-spaced receptors located along the facility fence line.
- A 100 meter grid containing 100 meter-spaced receptors, extending approximately 1.0 km from the fence line, exclusive of the fence line grid.
- A 250 meter grid containing 250 meter-spaced receptors, extending approximately 2.5 km from the fence line, exclusive of the 100 meter grid.
- A 500 meter grid containing 500 meter-spaced receptors, extending approximately 5.0 km from the fence line, exclusive of the 250 meter grid.
- A 750 meter grid containing 750 meter-spaced receptors, extending approximately 7.5 km from the fence line, exclusive of the 500 meter grid.
- A 1,000 meter grid containing 1,000 meter-spaced receptors, extending approximately 10 km from the fence line, exclusive of the 750 meter grid.

Stack & Emissions Data

A summary of the modeled emission rates and stack parameters is presented below.

Site Stack Data

	Easting (m)	Northing (m)	Elev. (m)	Emission Rate (lb/hr)	Stack velocity (m/s)	Stack Temp. (K)	Stack Ht (m)	Stack Dia. (m)
Unit 1	707,666.9	3,871,631.3	290.61	2,294.78	42.31	392.59	13.57	4.57
Unit 2	707,666.9	3,871,696.5	289.58	2,278.21	42.31	392.59	13.57	4.57
Unit 3	707,668.3	3,871,751.5	288.65	2,423.72	30.93	424.26	27.62	5.49
Holcim	710,625.9	3,849,394.5	310.56	349.07	17.98	400.93	64.01	3.72

Modeling Results

The results presented in this section demonstrate that, when modeled in accordance with the most recently published guidance, OG&E Seminole does not cause or contribute to a violation of the NAAQS for CO.

Significance Analysis Results

Averaging Period	1-hour (µg/m3)	8-hour (µg/m3)
Maximum Modeled Concentration[1]	1,232	776
Significant Impact Level	2,000	500
Full Impact Analysis Required?	No	Yes

[1] - Based on the Highest 1st High.

SMC Analysis Results

Averaging Period	1-hour (µg/m3)	8-hour (µg/m3)
Maximum Modeled Concentration[1]	1,232	776
Significant Monitoring Concentration	---	575
Above SMC?	N/A	Yes

[1] - Based on the Highest 1st High.

The reason for ambient monitoring is to establish the existing background concentrations in the vicinity of the proposed source or modification. The background concentrations are important in determining compliance with the NAAQS. Since the maximum modeled impacts for the 8-hour averaging period exceeds the SMC, OG&E had to demonstrate that existing monitoring data was adequate enough to represent the current ambient concentrations in the area surround the Seminole facility. The *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA 450/4-87-007) allows the use of "*monitoring data from a 'regional' site*" as "representative" air quality data "*If the proposed source or modification will be constructed in an area that is generally free from the impact of other point sources and area sources associated with human activities*".

The area around the OG&E facility is sparsely populated with little developed land. Based on the lack of development in the area and the high quality of data from existing monitoring sites, current monitoring data can be used in lieu of on-site data. OG&E proposed use of CO monitoring data from the Cherry Tree tribal monitor (40-001-9009) to fulfill the requirements for preconstruction monitoring for CO. However, this data set was missing approximately 23 percent of the data. The North OKC SLAMS monitoring data was used instead since it was missing approximately 1% of the data. The data collected at the North OKC monitor is representative of the local climate and area surrounding the OG&E Seminole facility and the resulting concentrations are still below the NAAQS.

NAAQS Analysis Results

Averaging Period	1-hour (µg/m3)	8-hour (µg/m3)
Maximum Modeled Concentration[1]	1,130	446
Background Concentration	1,145	916
Total Concentration	2,275	1,362
NAAQS	40,000	10,000
Cause or Contribute?	No	No

1 - Based on the Highest 2nd High.

SECTION VII. EMISSIONS

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

- Except for NO_X emissions which are based on the BART emission limitations and CO emissions which are based on established emission limit (0.465 lb/MMBTU), Boilers 1, 2, and 3 are based on the AP-42 (7/1998), Section 1.4, emission factors: 5.5 lb/MMSCF VOC, 7.6 lb/MMSCF PM_{10}, and 0.6 lb/MM SCF SO_2. To convert to lb/MMBTU divide by 1,020 BTU/SCF.

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

  Although the 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.
- Gasoline Storage Tank: EPA's "TANKS4.09" and AP-42 (1/1995), Section 5.1, Equation 1 and a throughput of 18,000 gallons per year.
- Auxiliary Boiler: manufacturer's data NO_2: 0.035 lb/MMBTU & CO: 0.0075 lb/MMBTU; AP-42 (7/1998), Section 1.4, VOC: 5.5 lb/MMSCF, $PM_{10}/PM_{2.5}$: 7.6 lb/MMSCF, and SO_2: 0.6 lb/MMSCF; and 3,100 hours of operation per year. To convert to lb/MMBTU divide by 1,020 BTU/SCF.

- Gas Turbine: AP-42 (4/2000), Section 3.1 emission factors for uncontrolled natural gas fired turbines: 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 and 500 hours of operation per year.
- HAP emissions from combustion of natural gas: AP-42 (7/1998), Section 1.4, except for n-hexane which is based on the FIRE Data System (0.42 lb/10^{12} BTU).
- Emergency generator and fire pump diesel fired engines: AP-42 (10/1996) emission factors: 0.031 lb/hp-hr NO_X, 0.0068 lb/hp-hr CO, 0.0025141 lb/hp-hr VOC, 0.0022 lb/hp-hr PM_{10}, 0.0205 lb/hp-hr SO_2, and 500 hours of operation a year.
- Radio tower emergency generator propane fired engine: NSPS, Subpart JJJJ emissions limits (40 CFR Part 90 [Phase 1, Class II]): 10.0 g/hp-hr HC+NO_X and 387 g/hp-hr CO; AP-42, Section 3.2 (8/2000) emission factors (assumes PM, VOC, and SO_2 are the same, on a heat input basis [0.38 MMBTUH], as natural gas): 0.0296 lb/MMBTU VOC, 0.1941 lb/MMBTU PM_{10}, 0.000588 lb/MMBTU SO_2, and 500 hours of operation a year.

Greenhouse gas emissions have been estimated at approximately 8.61 million TPY based on the total facility heat input, default emission factors from 40 CFR Part 98, Subpart C, and the Global Warming Potentials of 40 CFR Part 98, Subpart A.

Facility Wide Emissions After The Modification

	NO_X		CO		VOC		PM_{10}[1]		SO_2	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
2-B-01	1,112.4	4,872.5	2,548.2	11,161.1	29.55	129.42	40.83	178.84	3.22	14.12
2-B-02	1,161.8	5,088.5	2,548.2	11,161.1	29.55	129.42	40.83	178.84	3.22	14.12
2-B-03	901.3	3,947.9	2,555.6	11,193.7	29.64	129.80	40.95	179.36	3.23	14.16
3-B-03	1.41	2.19	0.30	0.47	0.22	0.95	0.30	1.32	0.02	0.10
4-B-01	96.00	24.00	24.60	6.15	0.63	0.16	1.98	0.50	0.18	0.05
5-B-05	----	----	----	----	----	0.72	----	----	----	----
6-B-01	9.30	2.33	20.40	5.10	0.75	0.19	0.66	0.17	6.15	1.54
6-B-02	5.49	1.37	12.04	3.01	0.44	0.11	0.39	0.10	3.63	0.91
6-B-03	0.88	0.22	34.13	8.53	0.01	0.01	0.07	0.02	0.01	0.01
Totals	**3,288.6**	**13,939.0**	**7,743.5**	**33,539.2**	**90.79**	**390.78**	**126.01**	**539.15**	**19.66**	**45.01**

1 - All PM_{10} is assumed to be $PM_{2.5}$.

Facility Wide HAP Emissions

	Emissions	
HAP	**lb/hr**	**TPY**
Benzene	0.035	0.151
Dichlorobenzene	0.020	0.086
Formaldehyde	1.234	5.405
n-Hexane	0.007	0.031
Toluene	0.056	0.245
Total HAP		**5.918**

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]
<u>Part 5</u> 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 permit application, operating permit, 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.

EU	Description	MMBTUH	SC 19 Limit lb/hr	Emissions lb/hr
2B-01	Unit 1 boiler	5,480	656.77	40.83
2B-02	Unit 2 boiler	5,480	656.77	40.83
2B-03	Unit 3 boiler	5,496	658.11	40.95
3B-01	Gas turbine	300	80.24	1.98
3B-02	Aux boiler	40.4	17.43	0.30

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.

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]
<u>Part 5</u> limits sulfur dioxide emissions from new fuel-burning equipment (constructed after July 1, 1972). New fuel-burning equipment includes any equipment that is modified after July 1, 1972. All of the fuel-burning equipment at this facility was constructed prior to the applicability date, except for the new auxiliary boiler.

"Modification" means any physical change in, or change in the method of operation of, a source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. None of the modifications of the existing boilers will increase emissions of SO_2 from the boilers.

For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over three hours. For fuel gas having a gross calorific value of 1,000 BTU/SCF, this limit corresponds to fuel sulfur content of 1,203 ppmv. AP-42 (7/98), Table 1.4-2 lists the total SO_2 emissions for natural gas to be 0.6 lb/MMft^3 or about 0.0006 lb/MMBTU which is in compliance with Subchapter 31. The permit will require the use of commercial grade natural gas for the new auxiliary boiler.

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 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 [Applicable]

Emissions of several regulated pollutants exceed 100 TPY, the level at which PSD defines the facility to be a major source. Since the modification of the boilers resulted in a significant net emission increase of a regulated NSR pollutant as indicated in Section VI. PSD Review, this project was subject to PSD. The applicable BACT and modeling requirements were addressed in Section V. BACT Review and Section VI. Air Dispersion Modeling Review. 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}, 10 TPY PM2.5, or 0.6 TPY lead).

NSPS, 40 CFR Part 60 [Subparts Dc and JJJJ are Applicable]

<u>Subpart D</u>, 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. The physical changes that will be made to the boilers are not considered reconstruction since the costs are less than 50% of the cost of a new unit. Also, these units are not modified since there will not be an emission increase in kg/hr from the affected emission units.
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 40.4 MMBTUH steam generating unit was constructed after June 9, 1989, and is subject to this subpart. Since the auxiliary boiler only fires natural gas it is only subject to the recordkeeping requirements of § 60.48c(g).
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 and has not been modified or reconstructed.
Subpart IIII, Stationary Compression Ignition (CI) Internal Combustion Engines (ICE). This subpart affects CI ICE manufactured after 2007. There are no CI ICE manufactured after 2007 at this facility.
Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines (SI ICE). This subpart affects SI ICE ordered after June 12, 2006 and all SI ICE engines modified or reconstructed after June 12, 2006, regardless of size. The propane fired emergency generator engine (EU 6-B-03) is subject to this subpart.

Per § 60.4233(c), owners and operators of stationary SI ICE, with a maximum engine power greater than 25-hp, that are rich burn engines that use LPG, that commence construction after June 12, 2006, and that are manufactured on or after January 1, 2009, must comply with the emission standards in § 60.4231(c). Per § 60.4231(c), emergency stationary SI ICE with a maximum engine power greater than 25-hp and less than 130-hp must be certified to the Phase 1 emission standards in 40 CFR 90.103, applicable to Class II engines, and other requirements for new nonroad SI engines in 40 CFR Part 90.

§ 90.103, Table 1-Phase 1 Exhaust Emission Standards

Engine Class	Units	$HC+NO_X$	CO
II	**g/kw-hr**	13.4	519
	g/hp-hr	10.0	387

However, emergency stationary SI ICE, with a maximum engine power less than or equal to 40-hp, with a total displacement less than or equal to 1,000 CC, may be certified to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR Part 90 or 1054, as appropriate. These standards are listed below.

§ 90.103, Table 3-Phase 2 Exhaust Emission Standards for Model Year 2005 & Later

Engine Class	Units	$HC+NO_X$	$NMHC+NO_X$[1]	CO
II	g/kw-hr	12.1	11.3	610
	g/hp-hr	9.0	8.4	455

1 - $NMHC+NO_X$ standards are applicable only to natural gas fueled engines at the option of the manufacturer, in lieu of $HC+NO_X$ standards.

§1054.105, Table 1-Phase 3 Emission Standards for Nonhandheld Engines[1], Model Year 2011 and Later

Engine Class	Units	$HC+NO_X$	CO
II	g/kw-hr	8.0	610
	g/hp-hr	6.0	455

1 – For engine displacement ≥ 225 L.

The emission limits for the engine will be established at the Phase I exhaust emission standards. If the engine is operated and maintained according to the manufacturer's emission-related written instructions, the facility only has to keep records of conducted maintenance to demonstrate compliance. If the engine is not operated and maintained according to the manufacturer's emission-related written instructions, the facility must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In either case no performance testing is required.
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 Subpart KKKK and has not been modified or reconstructed.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride except for trace amounts of benzene. Subpart J, Equipment Leaks of Benzene, concerns only process streams that contain more than 10% benzene by weight. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.

NESHAP, 40 CFR Part 63 [Subparts ZZZZ & CCCCCC are 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. This facility is not a major source of HAP and is not subject to this subpart.
Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines):

1) Stationary RICE located at an area source;
2) The following Stationary RICE located at a major source of HAP emissions:
   i) 2SLB and 4SRB stationary RICE with a site rating of ≤ 500 brake HP;
   ii) 4SLB stationary RICE with a site rating of < 250 brake HP;
   iii) Stationary RICE with a site rating of ≤ 500 brake HP which combust landfill or digester gas equivalent to 10% or more of the gross heat input on an annual basis;
   iv) Emergency or limited use stationary RICE with a site rating of ≤ 500 brake HP; and
   v) CI stationary RICE with a site rating of ≤ 500 brake HP.

No further requirements apply for engines subject to NSPS under this part. Based on emission calculations, this facility is a minor source of HAP. Stationary RICE located at an area source of HAP emissions are new if construction commenced on or after June 12, 2006. The propane-fired emergency generator engine is subject to NSPS, Subpart JJJJ and will comply with this subpart by complying with NSPS, Subpart JJJJ.

The 300-hp Detroit Diesel emergency generator engine (EU 6-B-01) and the 177-hp emergency fire pump engine were constructed prior to June 12, 2006 and are considered existing stationary emergency sources. A summary of the requirements for existing SI RICE located at this facility are shown below.

Engine Category	Normal Operation[1] @ 15% O_2
Existing Emergency, CI RICE & Black Start CI RICE	Change oil and filter every 500 hours of operation or annually, whichever one comes first; Inspect air cleaner every 1,000 hours of operation or annually, whichever one comes first; and Inspect all hoses and belts every 500 hours of operation or annually, whichever one comes first and replace as necessary.

[1] During Startup - Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

Sources have the option to utilize an oil analysis program in order to extend the specified oil change requirements of this subpart. Initial compliance demonstrations must be conducted within 180 days after the compliance date. Owners and operators of a non-operational engine can conduct the initial compliance demonstration when the engine is started up again.

Other applicable requirements include:

1) The owner/operator must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop their own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

Additionally, there are limitations on the hours that an emergency engine may operate. Total operating hours are limited to 100 hours/year for maintenance and readiness checks unless Federal, State, or local standards require maintenance and testing beyond 100 hours per year. The 100 hours/year includes up to 50 hours of non-emergency operations. The 50 hours cannot include peak shaving or other income generating power production. The 50 hours includes up to 15 hours of power generation as part of a demand response program in the event of a potential electrical blackout situation. All applicable requirements have been incorporated into the permit.
Subpart CCCCCC, Gasoline Dispensing Facilities. This subpart establishes emission limitations and management practices for HAP emitted from the loading of gasoline storage tanks at gasoline dispensing facilities (GDF) located at an area source. GDF means any stationary facility which dispenses gasoline into the fuel tank of a motor vehicle. The affected source includes each gasoline cargo tank during the delivery of product to a GDF and also includes each storage tank.

If the GDF has a monthly throughput of less than 10,000 gallons of gasoline, it must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

1) Minimize gasoline spills;
2) Clean up spills as expeditiously as practicable;
3) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use;
4) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators.

This facility has a monthly throughput of less than 10,000 gallons of gasoline. All applicable requirements have been incorporated into the permit.
Subpart JJJJJJ, Commercial and Institutional Boilers. This subpart affects new and existing boilers located at area sources of HAP, except for gas-fired boilers. Gas fired boilers are defined as any boiler that burns gaseous fuel not combined with any solid fuels, liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing under this definition shall not exceed a combined total of 48 hours during any calendar year. The boilers at this facility meet the definition of gas fired boilers and are not subject to this subpart.

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;
2) Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act; and
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

This application has been determined to be Tier II based on the request for a construction permit for physical change which is considered a significant modification.

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.

Public Review

The applicant published the "Notice of Filing Tier II Application" in *The Seminole Producer* a weekly newspaper in Seminole County on December 10, 2014. The notice stated that the application was available for public review for a period of thirty days at the Kennedy Public Library located in Konawa and at the AQD main office. The applicant published the "Notice of

Draft Permit" in *The Seminole Producer* a weekly newspaper in Seminole County on February 12, 2015. The notice stated that the draft permit was available for public review for a period of thirty days at the Kennedy Public Library, the AQD main office, and on the Air Quality section of the DEQ web page at http://www.deq.state.ok.us. No comments were received from the public.

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/*.

State Review
The facility is not located within 50 miles of the Oklahoma border.

EPA Review
This permit was approved for concurrent public and EPA review. The draft/proposed permit was forwarded to EPA for a 45-day review period. Since no comments were received from the public, the draft/proposed permit was deemed the proposed permit. In a memo dated March 26, 2015, EPA submitted comments and questions, regarding the permit and permit memorandum. The responses to the comments and questions are addressed as follows: the EPA comment is given, then the OG&E response to the comment is given, and finally Air Quality Division's (AQD) response to the comment is given. Any changes to the permit or permit memorandum have been incorporated into the final permit and permit memorandum.

EPA Comment #1:
Please specify whether the Boiler Units 1, 2 & 3 are run continuously at full capacity or at restricted capacity for restricted hours as required to meet the demand and specify on which parameters the Projected Actual emissions (PAE) heat input was determined, such as results of historic maximum capability tests, design information from the manufacturer, or engineering calculations.

OG&E Response to Comment #1:
The boiler units do not run at full capacity on a continuous basis. In the past five years, they have operated at much less than full capacity, typically around a 30% capacity factor, as needed to meet demand. In projecting emissions after the project, OG&E considered all relevant information and decided that "historical operational data" provide the most reliable measure of the "company's highest projections of business activity" and the future maximum annual rate of emissions. 40 C.F.R. § 52.21(b)(41)(ii)(a); OAC 252:100-8-31 (defining "projected actual emissions"). Therefore, the Projected Actual Emissions for each pollutant were determined based on the highest 12-month actual heat input achieved at the units during the preceding five years. Actual heat input is measured by continuous monitoring of fuel flow to the burners.

AQD Response to Comment #1:
Boiler Units 1, 2, and 3 were run at reduced capacity as needed to meet the demand during the baseline period. The annual capacity factor for the boilers ranged from 19% to 31% during the baseline period.

The 30-day average heat input for Boiler Units 1, 2, and 3 were based on the monthly sum of the hourly continuous monitoring data. The annualized heat inputs for Boiler Units 1, 2, and 3 were based on the highest monthly (maximum 30-day rolling total) heat input times 12 months of operation. The projected actual emissions result in an annual capacity factor of 27%, 28%, and 31%, respectively using the maximum hourly heat input.

In the five years of data submitted by the applicant:

- Unit 1 was operational except for: an extended 3 month period from January to March 2010;
- Unit 2 was operational except for: April to May 2010, February to March 2012, and December of 2012.
- Unit 3 was operational except for: an extended 3 month period from April to June 2009, February 2011, December of 2011, and January 2012.

The footnotes for the project emission increase tables were updated to indicate that the heat input was based on historical operating data and resulted in the annual capacity factors given above.

Since the projected actual emissions were based on a resulting annual capacity factor of approximately 30%, any emissions excluded under accommodated emissions were allowed since the historical continuous monitoring data supports use of all three boilers at an annual capacity factor of 30%.

<u>EPA Comment #2:</u>
Please specify whether the Auxiliary Boiler is run continuously at full capacity or at restricted capacity for restricted hours as required to meet the demand and specify on which parameters the PAE heat input was determined, such as results of historic maximum capability tests, design information from the manufacturer, or engineering calculations.

<u>OG&E Response to Comment #2:</u>
As indicated in Section VII of the draft permit memorandum (page 16), the emission limits and other conditions for the replacement auxiliary boiler would restrict this unit to 3,100 hours of operation per year. OG&E calculated the annual heat input to the auxiliary boiler (125,240 MMBTU) by multiplying the heat capacity (40.4 MMBTUH) by 3,100 hours per year. Emissions were projected using the annual heat input and the emission factors shown in Section II of the draft permit memorandum.

<u>AQD Response to Comment #2:</u>
Projected actual emissions for the new auxiliary boiler were estimated using an annual capacity factor of approximately 35% and were based on engineering judgment and historical operation of the existing auxiliary boiler. This information was added to the footnotes for the project emission increase table for this emission unit. However, this emission unit did not take into account baseline actual emissions since it was a new emission unit and it also did not rely on the historical baseline actual emissions reductions from removal of the existing unit.

EPA Comment #3:
On page 2 of Permit Memorandum, it is noted that Unit 3 burns #6 fuel oil at times and that the burning of #2 fuel, waste oil, nonhazardous waste and 3,000 gallons of antifreeze per year is also allowed. Verify that the annual emission calculations have taken into account specially the CO and CO_{2e} emissions from these alternate fuels?

OG&E Response to Comment #3:
Projecting annual emissions for the boiler units based on emission factors for the combustion of fuel oil is not appropriate because the draft permit does not authorize the units to burn fuel oil. Specific Condition 1.a. for EUG2 in the draft permit says: "A permit modification shall be required to burn fuel oil in EU 2-B-01, 2-B-02, and 2-B-03."

Specific Condition 1.b. for EUG2 in the draft permit authorizes the combustion of non-hazardous waste that is generated on-site, from other OG&E facilities, or from OG&E employees and retired employees. Emission factors for the combustion of non-hazardous waste were not included in the annual emission projections because appropriate factors are not available and would not affect the outcome of the PSD analysis. Over the past five years, the non-hazardous waste combusted at Seminole has consisted of just 875.6 gallons of electro-hydraulic (EH) fluid, 7,795.3 gallons of used oil, and 195.0 gallons of solvent. There are no emission factors in AP-42 for the EH fluid or the solvent. There are factors in AP-42 for waste oil, but those factors were developed for small boilers, *i.e.* less than 250,000 BTU/hr, and would provide inaccurate results if applied to the much larger Seminole units. With respect to CO_{2e}, applying default emission factors from 40 CFR Part 98 to the amount of used oil combusted in the Seminole units during the last five years produces a total of just 92 tons of CO_{2e} (less than 20 tons per year). Emission factors for non-hazardous waste combustion would not affect the outcome of the PSD analysis because Seminole is projected to continue burning small amounts of such materials in the future.

AQD Response to Comment #3:
The statement related to combustion of fuel oil was based on the historical operation and permitted use of the boilers. Specific Condition No. 1, EUG 2, (a) states "a permit modification shall be required to burn fuel oil in EU 2-B-01, 2-B-02, and 2-B-03." Therefore, the current permit does not authorize combustion of fuel oil. The current permit still authorizes the facility 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 authorized wastes that may be combusted include: used oil, EH fluid, and used antifreeze. Projected actual emissions do not specifically include emissions from combustion of these non-hazardous materials.

The emission factor for CO is greater for burning natural gas than the emission factor for combustion of fuel oil. While CO and CO_2 emissions from combustion of the non-hazardous wastes may be greater than the emissions associated with combustion of natural gas, the emissions associated with burning the other non-hazardous materials at the facility do not significantly affect the total emissions from the facility. However, emissions from combustion of the relatively small amount of these non-hazardous materials are required to be incorporated into the total facility emissions and the total facility emissions must remain lower than the emissions limits established in the permit utilizing combustion of natural gas.

The opening remarks related to operation of these boilers in the permit memorandum have been updated to reflect the current operating permit specific conditions.

<u>EPA Comment #4:</u>
As specified in 40 CFR 52.21 (b)(41)(ii)(c), projected actual emissions shall

> " …exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth;"

OG&E Seminole's permit application relies on this exclusion for its PSD applicability analysis. In its application, OG&E Seminole states that it was capable of accommodating an additional heat input of production during the baseline period (referred to here as "the additional baseline capacity") than it actually produced during that period. OG&E Seminole also asserts that the emissions from this "additional baseline capacity" are unrelated to the Project and that these emissions are therefore excluded from its calculations of "projected actual emissions" as defined in 40 CFR 52.21(b)(41).

By its terms, however, 40 CFR 52.21 (b)(41)(ii)(c) sets forth a two-part test and both elements of the test must be satisfied in order to be able to exclude emissions under this provision of the rules. See State of New York v. EPA, 413 F.3d. 3, 33 (D. C. Cir. 2005) ("Thus, the regulations established two criteria a source must meet before excluding emissions from its projection….").

This two-part test is emphasized in the rulemaking record as well:

> *…. demand growth can only be excluded to the extent that the physical or operational change is not related to the emission increase. Thus, even if the operation of an emissions unit to meet a particular level of demand could have been accomplished during the representative baseline period, but it can be shown that the increase is related to the changes made to the unit, then the emission increases resulting from the increased operation must be attributed to the modification project, and cannot be subtracted from the projection of post-change actual emissions.*

67 Fed. Reg. 80186, 80203 (December 31, 2002). (emphasis added). See also Technical Support Document for the Prevention of Significant Deterioration and Nonattainment Area New Source Review Regulations, November 2002, at I-4-37.

In determining the emissions increase from the three existing boiler (Unit 1, Unit 2, and Unit 3), OG&E Seminole claims that using the projected actual emissions, as well as the "could have accommodated" provision results in zero tons per year (TPY) emissions increase for NO_X, VOC,

$PM_{10}/PM_{2.5}$, SO_2 and CO_{2e}. Further, the Permit Memorandum contains tables for each existing boiler to explain how they derived Project Emission Increases (PEI) with a short description in footnotes. However, not enough analysis was provided in the Permit Memorandum to support this claim. Please provide additional details in Permit Memorandum or in the permitting record to fully demonstrate that the emissions it seeks to exclude are unrelated to the project. ODEQ should determine what could have been accommodated by determining the highest production for a 30 day period (that's a 30 consecutive day time frame, not a few days here and a day or two there, added to obtain a 30 day value) during the baseline time frame, and verify that they have and will operate for 24 consecutive months without an extended shutdown. That annualized production rate represents what they could have produced during the baseline period. The actual emissions that would be associated with this annualized production rate are estimated by multiplying the ratio of the rate at which they could have produced and the actual production rate during the baseline period by the baseline emission rate. The facility should provide this information to support the use of the methodology consistent with Clean Air Act (CAA) and the Oklahoma State Implementation Plan (SIP). In addition, we have enclosed the April 20, 2010, letter from EPA Region 3 regarding Northampton Generating Company. The letter explains the appropriate methodology for using the projected actual emissions test for applicability, as well as the "could have accommodated" provision.

a. The calculation of product demand growth exclusion is not well documented in the permit record. For example, is OG&E's demand growth emission estimate based on "the maximum actual throughput, firing rate or emissions rate" experienced at all units? Is this hypothetical rate physically possible? In other words, is the rate one that the facility could physically achieve while still complying with its permit conditions and any other applicable Clean Air Act (CAA) regulatory requirements that the source is subject to.
b. Please provide documentation supporting the utilization factor in the record that the facility is physically capable of operating at the "could have accommodated" rate for an extended period of time.

<u>OG&E Response to Comment #4:</u>
The permitting record contains ample evidence to establish that excluded emissions are unrelated to the project. The project consists of installing one small auxiliary boiler and nitrogen oxide (NO_X) pollution control technologies to satisfy the BART regulatory requirement. Carbon monoxide (CO) is the only pollutant for which there will be a change in the applicable emissions factor (lb/MMBTU) for Boiler Units 1-3. OG&E and Oklahoma DEQ calculated the increase in annual CO emissions from Boiler Units 1-3 that will be caused by the Project by multiplying the projected annual heat input by the difference between the pre- and post-project CO emission factors. Because the resulting amount of CO emissions increase exceeds the PSD significant threshold, OG&E applied for a PSD permit for the CO emissions increase. CO is the only pollutant for which the installation of BART controls will cause a significant increase in emissions. There will be no change in emission factors for any other pollutant. Nor is there any reason to expect that installation of BART controls will increase the capacity of the units or cause OG&E to run them more. Thus, any future increases in emissions of pollutants other than CO from Boiler Units 1-3 will necessarily be caused by unrelated demand growth and not by the Project.

To further support the demand growth exclusion, emissions that could have been accommodated without the project (referred to as "Accommodated Emissions") were determined by annualizing the highest 30-day emissions from the selected 24-month baseline period in accordance with EPA guidance. Consistent with the approach that EPA recommends in the above comment, the highest 30-day emissions were selected from 30 consecutive days of operation (in September 2011 for Unit 1, December 2011 for Unit 2, and April 2013 for Unit 3). The draft permit memorandum accurately explains the Accommodated Emissions as "based on the annualized highest monthly heat input and the BAE emission factors except for NO_2, SO_2, and CO_2 which are based on the annualized highest monthly CEM emissions from the baseline period." Thus, Accommodated Emissions of NO_2, SO_2, and CO_2 were calculated as the annualized highest month of CEMS data from the selected baseline, while excluded emissions of other pollutants are based on the annualized highest monthly heat input and baseline emission factors. It would have been possible for the units to operate for 12 months without an "extended shutdown." The period of time that is relevant to this analysis is 12 months of operation, not 24 months as suggested in EPA's comment. Projected Actual Emissions is defined as the maximum annual rate, in tons per year, at which an existing unit is projected to emit a regulated NSR pollutant in any one of the following 5 years (12-month period). 40 C.F.R. § 52.21(b)(41)(ii)(a); OAC 252:100-8-31. Maintenance turnarounds lasting 6 weeks are scheduled for the Boiler Units every three years (36 months). Annual maintenance to prepare the units for the summer season lasts just 1 week each year.

EPA has approved of the highest demonstrated month of operation, annualized, as a reasonable approximation of the level of operation that a facility "could have accommodated" during the baseline period when applying the demand growth exclusion. In this case, however, the amount of emissions being excluded from the Projected Actual Emissions is much less than the full extent of the Accommodated Emissions. Excluded emissions for NO_X and CO_{2e} are equal to the difference between the Baseline Actual Emissions and the Projected Actual Emissions. The Projected Actual Emissions for each pollutant were determined based on the highest 12-month heat input during the preceding five years. Because the Projected Actual Emissions are based on actual 12-month operating data, it is clear that the units could have accommodated the full extent of the excluded emissions. It is also clear that the excluded emissions are not caused by the project for the reasons explained previously.

AQD Response to Comment #4:

Only emissions of NO_2, CO, and CO_2 have the possibility of exceeding the significant emission rates (40 TPY, 100 TPY, and 100,000 TPY). All other pollutants are below the significance levels when taking into account only PAE-BAE. The project has been determined to be subject to PSD for CO. The only pollutants which utilize accommodated emissions to reduce PAE from the boilers to below the PSD significance levels are NO_2 and CO_2.

Accommodated emissions were specifically not allowed to reduce emissions directly related to installation of the Low-NO_X burners. The new emission factor for the Low-NO_X burners for CO was 0.465 and the old emission factor was 0.082. The difference of the emission factors was not allowed to be excluded from the project emission increases.

The accommodated emissions were calculated in accordance with the Region VI Georgia Pacific memo dated March 18, 2010. The supplied Northampton memo from Region III dated April 20, 2010, does not include any mention of the annualized component when calculating emissions that the facility could have accommodated that is referenced in comment.

As previously stated, the projected actual emissions had a resulting annual capacity factor of approximately 30% and any emissions excluded under could have accommodated emissions were supported based on historical continuous monitoring data.

Fees Paid
Construction permit application fee for an existing Part 70 source fee of $5,000.

SECTION XI. SUMMARY

The facility has demonstrated the ability to comply with all applicable rules and regulations. 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 construction permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Oklahoma Gas & Electric Company **Permit No. 2010-594-C (M-2) PSD**
Seminole Generating Station **Facility ID: 1210**

The permittee is authorized to construct/operate in conformity with the specifications submitted to Air Quality on April 10, 2014, and all supplemental information. The Evaluation Memorandum dated April 28, 2015, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Commencing construction and/or 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)]

EUG 2 Boilers

EU ID#	Point ID#	EU Name	Manufacturer	MMBTUH	kW	Serial #
2-B	01	Unit 1 Boiler	Babcock & Wilcox El-Paso	5,480	509,719	BW-22731
2-B	02	Unit 2 Boiler	Babcock & Wilcox El-Paso	5,480	504,604	BW-22826
2-B	03	Unit 3 Boiler	Babcock & Wilcox El-Paso	5,496	505,980	BW-23416

Emission Limits* for EU 2-B-01, 2-B-02, & 2-B-03

EU/Point ID #	Units	NO_X	CO	PM_{10}	SO_2
2-B-01	**lb/hr**	1,112.4	2,548.2	40.83	3.22
BW-22731	**lb/MMBTU****	0.203	0.465	0.0075	0.0006
2-B-02	**lb/hr**	1,161.8	2,548.2	40.83	3.22
BW-22826	**lb/MMBTU****	0.212	0.465	0.0075	0.0006
2-B-03	**lb/hr**	901.3	2,555.6	40.95	3.23
BW-23416	**lb/MMBTU****	0.164	0.465	0.0075	0.0006

* - Except for CO, limits are established based on model inputs to demonstrate compliance with regional haze and impacts below 0.5 deciview; CO limits are based on the PSD BACT analysis.

** - Except for NO_X, emission limits are based on a 3-hour average; NO_X emission limits are based on a 30-day rolling average.

a. The permittee shall be authorized to utilize pipeline natural gas as the primary fuel for EU 2-B-01, 2-B-02, and 2-B-03. A permit modification shall be required to burn fuel oil in EU 2-B-01, 2-B-02, and 2-B-03. [OAC 252:100-31]

b. Boilers 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]

c. The permittee shall continuously monitor and record NO_X emissions from EU 2-B-01, 2-B-02, and 2-B-03 to demonstrate compliance with the applicable emission limits. [OAC 252:100-8-6(a)]

d. The boilers in EUG 2 (2-B-01, 2-B-02, & 2-B-03) 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]

i. 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

ii. Each existing affected facility shall install and operate the SIP approved BART, as expeditiously as practicable, but no later than January 27, 2017.

[OAC 252:100-8-75(e)]

iii. 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:

A. Low-NO_X Burners,

B. Overfire Air, and

C. Flue Gas Recirculation (Unit 3 is currently equipped with FGR).

iv. All of the burners in the affected facilities (Units 1 through 3) shall be Low-NO_X burners. 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 and continuously operated and maintained. [OAC 252:100-8-75(f)]

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

vi. After installation of the BART, the affected facilities shall only be fired with pipeline natural gas, except as authorized under Specific Condition 1.b.

[OAC 252:100-8-73(c)(1)]

vii. Within 60 days of 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 and CO 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 7: Determination of Nitrogen Oxides Emissions from Stationary Sources.

e. At least once a year, the permittee shall conduct tests of CO emissions from EU 2-B-01, 2-B-02, and 2-B-03 when operating under representative conditions to demonstrate compliance with the CO emission limits. Testing shall be conducted using approved reference methods. Written documentation of the results of emission testing shall be submitted with the most recent semi-annual monitoring report.

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

EUG 3 Auxiliary Boiler

EU ID#	Point ID#	EU Name/Model	Heat Capacity (MMBTUH)
3-B	03	Auxiliary Boiler Cleaver-Brooks Model CBEX Elite	40.4

Emissions Limits for EUG 3

	NO_X		CO	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**
3-B	1.41	2.19	0.30	0.47

a. The EU 3-B-03 shall only be fired with natural gas having 20.0 grains or less of total sulfur per 100 standard cubic feet. Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once annually. [OAC 252:100-31]

b. Boiler 3-B-03 shall be limited to 125.24 MMSCF in any 12-month period.

c. The permittee shall monitor and record the amount of fuel combusted in EU 3-B-03 each month to demonstrate compliance with the fuel throughtput limit. [OAC 252:100-8-6(a)]

d. EU 3-B03 is subject to NSPS for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR Part 60, Subpart Dc and shall comply with all applicable requirements including but not limited to: [40 CFR § 60.40c to § 60.48c]

i. § 60.40c Applicability and delegation of authority.
ii. § 60.41c Definitions.
iii. § 60.42c Standard for sulfur dioxide (SO2).

iv. § 60.43c Standard for particulate matter (PM).
v. § 60.44c Compliance and performance test methods and procedures for sulfur dioxide.
vi. § 60.45c Compliance and performance test methods and procedures for particulate matter.
vii. § 60.46c Emission monitoring for sulfur dioxide.
viii. § 60.47c Emission monitoring for particulate matter.
ix. § 60.48c Reporting and recordkeeping requirements.

The EU in **EUG 4** is "grandfathered" (pre-October 1972 construction) and is limited to the equipment as is.

EUG 4 Gas Turbine

EU ID#	Point ID#	EU Name/Model	MMBTUH	kW	Serial #	Const. Date
4-B	01	Gas Turbine/ General Electric	300	20,150	179530	5/28/70

a. The permittee shall be authorized to utilize natural gas as the primary fuel for EU 4-B-01. [OAC 252:100-19 & 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	Capacity (Gallons)	Installation Date
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]
b. The gasoline dispensing facility (GDF) (5-B) is subject to the NESHAP for GDF 40 CFR Part 63, Subpart CCCCCC and shall comply with all applicable requirements including but not limited to: [40 CFR § 63.11110 to § 63.11320]

<u>What This Subpart Covers</u>

(1) § 63.11110 What is the purpose of this subpart?
(2) § 63.11111 Am I subject to the requirements in this subpart?
   (i) The affected source to which 40 CFR Part 63, Subpart CCCCCC applies is each GDF that is located at an area source. The affected source includes each gasoline cargo tank during the delivery of product to a GDF and also includes each storage tank. [§ 63.11111(a)]
   (ii) If your GDF has a monthly throughput of less than 10,000 gallons of gasoline, you must comply with the requirements in § 63.11116. [§ 63.11111(b)]
   (iii) An affected source shall, upon request by the Administrator, demonstrate that their monthly throughput is less than the 10,000-gallon or 100,000-gallon threshold level, as applicable. For existing sources, as specified in § 63.11112(d), recordkeeping to document monthly throughput must begin on January 10, 2008. For existing sources that are subject to this subpart only

because they load gasoline into fuel tanks other than those in motor vehicles, as defined in § 63.11132, recordkeeping to document monthly throughput must begin on January 24, 2011. Records required under this paragraph shall be kept for a period of 5 years. [§ 63.11111(e)]

(iv) Monthly throughput is the total volume of gasoline loaded into, or dispensed from, all the gasoline storage tanks located at a single affected GDF. If an area source has two or more GDF at separate locations within the area source, each GDF is treated as a separate affected source. [§ 63.11111(h)]

(v) If your affected source's throughput ever exceeds an applicable throughput threshold, the affected source will remain subject to the requirements for sources above the threshold, even if the affected source throughput later falls below the applicable throughput threshold. [§ 63.11111(i)]

(vi) The dispensing of gasoline from a fixed gasoline storage tank at a GDF into a portable gasoline tank for the on-site delivery and subsequent dispensing of the gasoline into the fuel tank of a motor vehicle or other gasoline-fueled engine or equipment used within the area source is only subject to § 63.11116. [§ 63.11111(j)]

(3) § 63.11112 What parts of my affected source does this subpart cover?

(i) The emission sources to which 40 CFR Part 63, Subpart CCCCCC applies are gasoline storage tanks and associated equipment components in vapor or liquid gasoline service at new, reconstructed, or existing GDF that meet the criteria specified in § 63.11111. The equipment used for the refueling of motor vehicles is not covered by 40 CFR Part 63, Subpart CCCCCC. [§ 63.11112(a)]

(ii) An affected source is a new affected source if you commenced construction on the affected source after November 9, 2006, and you meet the applicability criteria in § 63.11111 at the time you commenced operation. [§ 63.11112(b)]

(iii) An affected source is reconstructed if you meet the criteria for reconstruction as defined in § 63.2. [§ 63.11112(c)]

(iv) An affected source is an existing affected source if it is not new or reconstructed. [§ 63.11112(d)]

(4) § 63.11113 When do I have to comply with this subpart?

(i) If you have an existing affected source, you must comply with 40 CFR Part 63, Subpart CCCCCC no later than January 10, 2011. [§ 63.11113(b)]

<u>Emission Limitations and Management Practices</u>

(5) § 63.11115 What are my general duties to minimize emissions?

(i) Each owner or operator of an affected source under this subpart must comply with the requirements of § 63.11115(a) and (b).

(6) § 63.11116 Requirements for facilities with monthly throughput of less than 10,000 gallons of gasoline.

(i) You must not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following: [§ 63.11116(a)]

(A) Minimize gasoline spills; [§ 63.11116(a)(1)]

(B) Clean up spills as expeditiously as practicable; [§ 63.11116(a)(2)]

(C) Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use; [§ 63.11116(a)(3)]

(D) Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators. [§ 63.11116(a)(4)]

(ii) You are not required to submit notifications or reports as specified in § 63.11125, § 63.11126, or subpart A of this part, but you must have records available within 24 hours of a request by the Administrator to document your gasoline throughput. [§ 63.11116(b)]

(iii) You must comply with the requirements of 40 CFR Part 63, Subpart CCCCCC by the applicable dates specified in § 63.11113. [§ 63.11116(c)]

(iv) Portable gasoline containers that meet the requirements of 40 CFR Part 59, subpart F, are considered acceptable for compliance with § 63.11116(a)(3). [§ 63.11116(d)]

<u>Notifications, Records, and Reports</u>

(7) § 63.11130 What parts of the General Provisions apply to me?

(i) 40 CFR Part 63, Subpart CCCCCC, Table 3 shows which parts of the General Provisions apply to you. [§ 63.11130]

(8) § 63.11131 Who implements and enforces this subpart?

(9) § 63.11132 What definitions apply to this subpart?

EUG 6 (Emergency Equipment):

EU ID#	Point ID#	EU Name Model	Serial #	Capacity (HP)	Const. Date
6-B	01	Emergency Generator Detroit Diesel 7123-7300	185A1417P1	300	1970
6-B	02	Emergency Fire Pump Detroit Diesel 6-71 RC-56	6A 01 90675	177	1970
6-B	03	Emergency Generator Generac QT025A	6215205	40	2011

a. The owner/operator shall comply with all applicable requirements of the NESHAP: Reciprocating Internal Combustion Engines, Subpart ZZZZ, no later than May 3, 2013, for each affected facility including but not limited to:

<u>What This Subpart Covers</u>

(1) § 63.6580 What is the purpose of subpart ZZZZ?

(2) § 63.6585 Am I subject to this subpart?

(3) § 63.6590 What parts of my plant does this subpart cover?

(4) § 63.6595 When do I have to comply with this subpart?

(i) If you have an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. [§ 63.6595(a)(1)]

Emission and Operating Limitations

(5) § 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary CI RICE located at an area source of HAP emissions?

(i) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d of 40 CFR Part 63, Subpart ZZZZ which apply to you. [§ 63.6603(a)]

(A) Change oil and filter every 500 hours of operation or annually, whichever comes first or utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement. [Table 2d, 40 CFR part 63, Subpart ZZZZ]

(B) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and [Table 2d, 40 CFR part 63, Subpart ZZZZ]

(C) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. [Table 2d, 40 CFR part 63, Subpart ZZZZ]

General Compliance Requirements

(6) § 63.6605 What are my general requirements for complying with this subpart?

Testing and Initial Compliance Requirements

(7) § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?

(i) You must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [§ 63.6625(e)(2)]

(ii) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed. [§ 63.6625(f)]

(iii) You have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Table 2d of 40 CFR Part 63, Subpart ZZZZ. [§ 63.6625(i)]

(8) § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

Continuous Compliance Requirements

(9) § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(i) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 2d of 40 CFR Part 63, Subpart ZZZZ that apply to you according to methods specified in Table 6 of 40 CFR Part 63, Subpart ZZZZ. [§ 63.6640(a)]

(ii) If you own or operate an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in § 63.6640(f)(1)(i) through (iii). Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in § 63.6640(f)(1)(i) through (iii), is prohibited. If you do not operate the engine according to the requirements in § 63.6640(f)(1)(i) through (iii), the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines. [§ 63.6640(f)(1)]

(A) There is no time limit on the use of emergency stationary RICE in emergency situations. [§ 63.6640(f)(1)(i)]

(B) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year. [§ 63.6640(f)(1)(ii)]

(C) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by § 63.6640(f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power. [§ 63.6640(f)(1)(iii)]

Notifications, Reports, and Records

(10) § 63.6655 What records must I keep?

(i) You must keep the records required in Table 6 of 40 CFR Part 63, Subpart ZZZZ to show continuous compliance with each emission or operating limitation that applies to you. [§ 63.6655(d)]

(ii) if you own or operate an existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d of 40 CFR Part 63, Subpart ZZZZ, you must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan. [§ 63.6655(e)(3)]

(iii) If you own or operate an existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response. [§ 63.6655(f)(2)]

(11) § 63.6660 In what form and how long must I keep my records?

(i) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1). [§ 63.6660(a)]

(ii) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. [§ 63.6660(b)]

(iii) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). [§ 63.6660(c)]

Other Requirements and Information

(12) § 63.6665 What parts of the General Provisions apply to me?

(i) Table 8 of 40 CFR Part 63, Subpart ZZZZ shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. [§ 63.6665(a)]

(13) § 63.6670 Who implements and enforces this subpart?

(14) § 63.6675 What definitions apply to this subpart?

b. The permittee shall comply with all applicable requirements of the New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines, Subpart JJJJ, for each affected engine including but not limited to the following:

What This Subpart Covers

(1) 60.4230 Am I subject to this subpart?

Emission Standards for Owners and Operators

(2) 60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

(3) 60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?
<u>Other Requirements for Owners and Operators</u>
(4) 60.4236 What is the deadline for importing or installing stationary SI ICE produced in the previous model year?
<u>Compliance Requirements for Owners and Operators</u>
(5) 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?
<u>Testing Requirements for Owners and Operators</u>
(6) 60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?
<u>Notification, Reports, and Records for Owners and Operators</u>
(7) 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?
<u>General Provisions</u>
(8) 60.4246 What parts of the General Provisions apply to me?

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. Emission data for EU 2-B-01, 2-B-02, and 2-B-03, showing compliance with the BART emission limits (30-day rolling average).
e. Operating hours for each boiler.
f. Sulfur content of fuels per 40 CFR Part 75.
g. Periodic testing as required by Specific Condition No. 1, EUG 2(e).
h. Fuel consumption for EU 3-B-03 (monthly and 12-month rolling total).
i. For fuel(s) burned, the appropriate document(s) as described in Specific Condition No. 1, EUG 3 (a).
j. Records required by 40 CFR Part 60, Subparts Dc and JJJJ.
k. Records required by 40 CFR Part 63, Subparts ZZZZ and CCCCCC.

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. No recordkeeping is required for those operations which qualify as Trivial 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. No later than 30 days after each six month period, after the date of issuance of the original Part 70 operating permit (6/21/1999), the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from the permit requirements since the previous report shall be clearly identified in the report. [OAC 252:100-8-6(a)(3)(C)(i) & (ii)]

Oklahoma Gas & Electric
Attn: Robert F. Benham
Alternate Designated Responsible Official
P. O. Box 321
Oklahoma City, OK 73101

Re: Permit Application No. **2010-594-C (M-2) PSD**
Seminole Generating Station
Facility ID: 1210
Seminole County, Oklahoma

Dear Mr. Benham:

Enclosed is the permit authorizing construction/modification of the referenced facility. Please note that this permit is issued subject to the certain standards and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

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

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at eric.milligan@deq.ok.gov or at (405) 702-4217.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
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. 2010-594-C (M-2) PSD

Oklahoma Gas & Electric

having complied with the requirements of the law, is hereby granted permission to construct/modify 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.

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

Division Director **Date**
Air Quality Division

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]