OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **October 6, 2015**

TO:	Phillip Fielder, P.E., Permits and Engineering Group Manager
THROUGH:	Phil Martin, P.E., Engineering Manager, Existing Source Permits Section
THROUGH:	Peer Review
FROM:	Mark Chen, P.E., New Source Permits Section
SUBJECT:	Evaluation of Construction Permit Application **No. 2010-496-C (M-2) PSD** American Electric Power (AEP) Public Service Company of Oklahoma (PSO) Comanche Power Station (Facility ID: 0211) Latitude N 34.54176°, Longitude W 98.32449° Section 23, Township 1N, Range 11W Lawton, Comanche County, Oklahoma Directions: From Lawton, go 4 miles east on Highway 7, turn south at the KSWO TV station, go 3 miles south and turn west into the site.

SECTION I. INTRODUCTION

American Electric Power (AEP) has requested a construction permit for their Comanche Power Station (SIC 4911, NAIC Code 221112) to install Dry Low-NO_X burners (DLNB) to Units No. 1 and No. 2 to reduce emissions of NO_X for the purpose of meeting Best Available Retrofit Technology (BART) requirements and Regional Haze Rule. The Comanche Power Station is owned by Public Service Company of Oklahoma (PSO) and the PSO is a subsidiary of AEP. Currently, the Comanche Power Station is operating under Permit No. 2010-496-TVR2 (M-1), issued on March 26, 2013. The initial Title-V Permit No. 97-089-TV was issued on June 21, 1999. The facility is an electric utility plant, which burns natural gas to generate electricity. The Comanche Power Plant was constructed in 1971 and has operated continuously since that time without significant modification.

The BART-applicable units in this facility are two fossil-fuel fired steam electric plants with heat inputs greater than 250-MMBtu/hr (Units 1G1 and 1G2 in EUG 2). Both units were in existence prior to August 7, 1977, but were not in operation prior to August 7, 1962. Both units have the potential to emit more than 250 tons per year of NOx, which is a visibility impairing pollutant. Therefore, Units 1G1 and 1G2 meet the definition of a BART-eligible sources. Because the units fire natural gas, emissions of sulfur dioxide (SO_2) and particulate matter (PM) are minimal. There are no SO_2 or PM post-combustion control technologies with a practical application to natural gas-fired turbines. BART is good combustion practices. A full BART analysis was conducted for NOx application to natural gas-fired turbines.

BART Controls and Limits

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

In DLNB, the mixing of fuel and air thoroughly prior to reaction allows all burning to occur at relatively lean fuel-to air (F/A) ratios. High F/A ratios and stoichiometric combustion are eliminated, so that peak combustion temperatures are held below the temperature of significant NOx formation. This reduces the amount of oxygen in the hottest part of the flame and reduces NOx. However, the changes to combustion result in an increase of CO emissions. There are no anticipated changes to PM_{10}, $PM_{2.5}$, SO_2, GHG, and VOC emissions.

Since the project involves a physical change to an existing unit, the applicant has prepared a PSD analysis of Projected Actual Emissions (PAE) compared to Baseline Actual Emissions. All emissions changes are below PSD levels of significance except for CO. Upon applicant's request, this permit will proceed through a concurrent public and EPA review.

SECTION II. FACILITY DESCRIPTION

The facility produces power using two Westinghouse gas combustion turbines, Model W-501B, to supply a single steam turbine. Each gas turbine is rated at 94 MW (gross MW output) and the steam turbine is rated 120 MW (gross MW output). The total combined output from the gas turbines and steam turbine is 308 MW. The gas turbines are operated on natural gas. Pipeline quality natural gas has been the only fuel for the turbines since 1995. All turbines are continuously operated. Also on-site are two 2,700-hp diesel-fired emergency generators, one 2,100,000-gallon fuel oil tank, one 16,000-gallon diesel fuel tank, and one 16,800-gallon natural gas condensate tank.

SECTION III. EQUIPMENT

Emission units have been arranged into Emission Unit Groups (EUGs) as outlined below.

EUG 1. Facility-Wide Emissions Unit Groups

This emission unit group is facility-wide. It includes all emission units and is established to discuss the applicability of those rules or compliance demonstrations which may affect all sources within the facility.

EUG 2. Combustion Gas Turbines

EU ID#	Point ID#	EU Name/Model	MMBTUH	MW	Serial No.	Const. Date
1G1	1G1	Westinghouse /W-501B	1,250	94	17A8012	May 1971
1G2	1G2	Westinghouse /W-501B	1,250	94	17A8014	May 1971

EUG 3. VOL Storage Tanks

EU ID#	Point ID#	Contents	Capacity		Construction
			Barrels	Gallons	Date
TANK1	T-1	Fuel Oil	50,000	2,100,000	Sept. 1972
TANK2	T-2	Diesel Fuel	380	16,000	Sept. 1980
TANK3	T-3	Condensate	400	16,800	August 1972*

*This tank is owned and operated by the natural gas supplier, Enable, Inc.

EUG 4. Emergency Generators

EU ID#	Point ID#	Make/Model	hp	Serial #	Const. Date
EG1	EG1	General Motors/MP-36	2,700	63076	April 1962*
EG2	EG2	General Motors/MP-36	2,700	63075	April 1962*

*These two units were moved to Comanche Station in 1990.

EUG 5. Fugitive Emissions

Fugitive emissions at this facility are de minimis.

STACK PARAMETERS

Stack ID#	Source	Height	Diameter	Temperature	Flowrate
		(feet)	(feet)	(degrees F)	(ACFM)
8746	Unit 1G1	53	10.2	355	743,400
8747	Unit 1G2	53	10.2	359	743,400
17407	Diesel Generators	8	11.8	580	10,835

SECTION IV. AIR EMISSIONS

Emissions Changes

Regarding the turbines' heat input numerical values, the heat input is chosen by the high value over the last five year period for Unit No. 1 during the 2011-2012 period, and 2008-2009 period for Unit No. 2 according to the EPA Air Markets Division. Table 1 shows the baseline heat input and the projected actual heat input, these two values are the same.

Table 1. Turbines Heat Input

Sources	Baseline Heat Input (MMBTU/yr)	Projected Actual Heat Input (MMBTU/yr)
Unit 1G1	8,748,214	8,748,214
Unit 1G2	9,214,257	9,214,257

Regarding emission factors for turbines, only the CO and NOx factors are changed before and after the DLNB installation. Before DLNB installation, the CO emission factor was determined by the test result, which was conducted on January 9 and 10, 2015, as 0.9 ppmv, then, converted to 0.002 lb/MMBTU. The NOx emission factor was based on the high value of the last five years. These emissions factors are used for baseline emission factors. After DLNB installation, the CO emission factor is based on the vendor guarantee plus a margin of safety, equivalent to 35 ppmv, then, converted to 0.0785 lb/MMBTU, and the NOx emission factor is the BART limit. Table 2 shows the emission factors. These emissions factors are used for projected actual emission factors.

Table 2. Turbines Emission Factors for CO and NOx

Sources	CO (lb/MMBTU)		NOx (lb/MMBTU)	
	Before Installation	After Installation	Before Installation	After Installation
Unit 1G1	0.002	0.0785	0.5342	0.1500
Unit 1G2	0.002	0.0785	0.5737	0.1500

Regarding other emission factors for turbines, such as, SO_2, PM, VOC and GHG, the emissions factors remains unchanged before and after the DLNB installation and emissions factors are applicable to both units, Unit 1G1 and Unit 1G2. Table 3 shows the emission factors for turbines. Table 4 and 5 show the net emissions changes for turbines Unit 1G1 and Unit 1G2, respectively.

Table 3. Other Turbines Emission Factors

Pollutant	Emission Factor, lb/MMBTU	Factor Reference
SO_2	0.0034	AP-42 (4/00) Section 3.1, & 1,000 BTU/SCF Heating Value
PM_{10}	0.0066	AP-42 (4/00) Section 3.1, & 1,000 BTU/SCF Heating Value
$PM_{2.5}$	0.0066	AP-42 (4/00) Section 3.1, & 1,000 BTU/SCF Heating Value
VOC	0.0021	AP-42 (4/00) Section 3.1, & 1,000 BTU/SCF Heating Value
GHG	116.7	40 CFR Part 98

Table 4. Net Emissions Changes Turbine Unit 1G1 (8,748,214 MMBTU/yr)

Pollutant	Projected Actual Emissions TPY	Baseline Actual Emissions TPY	Net Changes TPY	PSD Level of Significance TPY	PSD Applicable
NOx	656	2,337	-1,681	40	No
CO	343.37	8.75	334.62	100	Yes
SO_2	15	15	0.0	40	No
PM_{10}	29	29	0.0	15	No
$PM_{2.5}$	29	29	0.0	10	No
VOC	9	9	0.0	40	No
GHG	510,960	510,960	0.0	75,000	No

Only CO net emissions changes are above PSD levels of significance.

Table 5. Net Emissions Changes Turbine Unit 1G2 (9,214,257 MMBTU/yr)

Pollutant	Projected Actual Emissions TPY	Baseline Actual Emissions TPY	Net Changes TPY	PSD Level of Significance TPY	PSD Applicable
NOx	691	2,643	-1,952	40	No
CO	361.66	9.21	352.45	100	Yes
SO_2	16	16	0.0	40	No
PM_{10}	30	30	0.0	15	No
$PM_{2.5}$	30	30	0.0	10	No
VOC	10	10	0.0	40	No
GHG	538,180	538,180	0.0	75,000	No

Only CO net emissions changes are above PSD levels of significance.

Criteria Pollutants

Before DLNB installation, the criteria pollutants emissions from the facility are estimated based on the latest AP-42 emission factors. The criteria pollutants emissions from the gas turbine are based on the emission factors in AP-42 (4/00), Tables 3.1-1 and 3.1-2a, Section 3.1, "Stationary Gas Turbine for Electricity Generation." For estimation purpose, the natural gas is assumed to have 1,000 BTU/SCF average heating value. The emission factors listed in Table 6A are uncontrolled emission factors and are expressed in the unit of lb/MMBTU.

Table 6A. Emission Factors for Gas Turbines Before DLNB Installation (lb/MMBTU)

Fuel	NOx	CO	SO_2	VOC	PM
Natural Gas	0.320	0.0820	0.0032	0.00210	0.0066

Dry low NOx burners (DLNB) are used in Units 1G1 and 1G2 for combustion control. DLNB limit NOx formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. DLNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperature resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperatures to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation. The NOx emission factor is reduced to 0.150 lb/MMBTU. The CO emission factor associated with the reduction of NOx emission factor is also changed to 0.0785 lb/MMBTU based on a PSD review. Table 6B shows uncontrolled emission factors, which are expressed in the unit of lb/MMBTU.

Table 6B. Emission Factors for Gas Turbines After DLNB Installation (lb/MMBTU)

Fuel	NOx	CO	SO_2	VOC	PM
Natural Gas	0.150	0.0785	0.0032	0.00210	0.0066

During startups and shutdowns alternate emission limits apply to the turbines. In general, both startup and shutdown periods include three combustion modes, (1) Primary Mode, (2) Lean-Lean Mode, and (3) Premix Mode. The Premix Mode is the steady and normal operation mode. Startup events shall not exceed nine hours per turbine and consists of the general phases noted. Shutdown events shall not exceed three hours per turbine. The facility will be limited to 75 startups and shutdowns per year, for each turbine. In testing situations required to fulfill North American Electric Reliability Corporation (NERC) mandates, the unit is not required to achieve pre-mix mode. Emission limits for NOx and CO during startups and shutdowns shall be as listed in Specific Condition No. 1. The following definitions apply as well as the emission limitations for each turbine listed below.

(1) Startup: Startup for each gas turbine begins when fuel is supplied to the Gas Turbine and combustion is initiated. Startup ends when the gas turbine reaches pre-mix mode (as directed by the control system).

(2) Shutdown: Shutdown begins when the turbine exits pre-mix mode for the purpose of shutting down. Shutdown ends with the termination of fuel flow to the turbine.
(3) Cold Start: A startup beginning more than 24 hours after the same unit shutdown.
(4) Warm Startup: A startup beginning less than 24 hours after the same unit shutdown.

Table 7. Emission Factors for Turbines During Startups and Shutdowns

Event	Maximum Duration (hr)	NOx (lb/MMBTU)	CO (lb/MMBTU)
Startup (cold)	9	0.35 lb/MMBTU*	0.6726 lb/MMBTU**
Startup (warm)	6	0.35 lb/MMBTU*	0.6726 lb/MMBTU**
Shutdown	3	0.35 lb/MMBTU*	0.6726 lb/MMGTU**

* Average E.F. **Highest E.F. among the three modes.

Table 8. Emission for Turbine During Startups and Shutdowns (Single Unit)

Event	Maximum Duration (hr)	NOx (lb/Event)	CO (lb/Event)
Startup (cold)	9	1,763	1,077
Startup (warm)	6	1,763	1,077
Shutdown	3	569	364

The criteria pollutants emissions from the emergency generators are based on the emission factors in AP-42 (10/96), Tables 3.4-2 and 3.4-5, Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines." The emission factors listed in Table 9 are uncontrolled emission factors and are expressed in the unit of lb/MMBTU.

Table 9. Emission Factors for Emergency Generators (lb/MMBTU)

Fuel	NOx	CO	SO_2	VOC	PM_{10}
No.2 Fuel Oil	3.200	0.850	0.0505	0.082	0.100

The potential emissions for the facility are estimated based on the 8,760 hour/year continuous operation for gas turbines, and 500 hour/year for emergency generators. The selection of 500 hours/year is based on the EPA memo (September 6, 1995), "Calculating Potential to Emit for Emergency Generators" which states that 500 hours is an appropriate default for estimating emissions from these sources. In 2010, Gas Turbine 1G1 operated 7,639 hours per year, Gas Turbine 1G2 operated 7,490 hours per year, and the emergency generators operated 28 hours per year.

The 400-bbl condensate tank, TANK3, is owned and operated by the natural gas supplier, Enable, Inc. This tank is used to collect the condensate from the natural gas stream inlet knockout pot. Based on the Enable operation record, there are not any condensate loadout data recorded from this tank in the last fifteen years. Therefore, the VOC emissions from this tank are considered negligible. In the next page, Table 10 shows facility-wide potential emissions after DLNB installation. Only the annual emissions of NOx and CO in TPY are estimated based on including emissions from 75 startup/shutdown periods for each turbine in a year. The other emissions do not include the emissions from startup/shutdown periods.

Table 10. Facility-Wide Potential Emissions After DLNB Installation

	NOx		CO		SO_2		VOC		PM	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Unit 1G1	187.50*	824.33**	98.13*	439.67**	4.00	17.52	2.63	11.5	8.25	36.14
Unit 1G2	187.50*	824.33**	98.13*	439.67**	4.00	17.52	2.63	11.5	8.25	36.14
Unit EG1	22.68	5.67	5.88	1.47	0.35	0.09	0.57	0.14	0.68	0.17
Unit EG2	22.68	5.67	5.88	1.47	0.35	0.09	0.57	0.14	0.68	0.17
TOTAL	**420.36**	**1,660.00**	**208.02**	**882.28**	**8.70**	**35.22**	**6.40**	**23.28**	**17.86**	**72.62**

* Normal operation only, does not including startup/shutdown periods

** Including startup/shutdown periods, 75 periods per year

Hazardous Air Pollutants (HAPs)

When the natural gas is burned, the hazardous air pollutant (HAP) emissions from the gas-fired stationary gas turbines are based on the emission factors in AP-42 (4/00), Table 3.1-3, Section 3.1, "Stationary Gas Turbine for Electricity Generation." Table 11 shows the HAP emissions from the gas turbines, which are estimated based on the total rate, 2,500 MMBTUH, and the continuous operation at 8,760 hours/yr.

Table 11. HAP Emissions from the Gas Turbines When Burning Gas

HAP	E.F.	Emissions	
	lb/MMBTU	**lb/hr**	**TPY**
1,3-Butadiene	4.30E-07	0.0011	0.0047
Acetaldehyde	4.00E-05	0.1000	0.4380
Acrolein	6.40E-06	0.0160	0.0701
Benzene	1.20E-05	0.0300	0.1314
Ethylbenzene	3.20E-05	0.0800	0.3504
Formaldehyde	7.10E-04	1.7750	7.7745
Napthalene	1.30E-06	0.0033	0.0142
PAH	2.20E-06	0.0055	0.0241
Propylene Oxide	2.90E-05	0.0725	0.3176
Toluene	1.30E-04	0.3250	1.4235
Xylenes	6.40E-05	0.1600	0.7008
Total		2.5683	**11.2493**

The HAP emissions from emergency generators and storage tanks are negligible and not included. Therefore, the facility-wide HAP emissions are summarized in Table 12. .

Table 12. Facility-Wide HAP Emissions

	Natural Gas-Fired	
Source	**lb/hr**	**TPY**
Gas Turbines	2.568	11.25
Total	**2.568**	**11.25**

In summary, Table 12 shows that no individual HAP exceeds 10 TPY, which is the major source threshold for a single HAP and the total HAP emissions are below 25 TPY, which is the major source threshold for combined HAPs. This indicates that the facility is a HAP minor source.

Greenhouse Gas (GHG))

Potential Greenhouse Gas (GHG) emissions from the facility were estimated using engineering calculations and gas analysis data (mole % value of gas component) from the facility. GHG emissions are expressed as CO_2e. All CO_2e emissions from combustion of natural gas are based on the default factors for natural gas combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2, and the related global warming potential factors from 40 CFR Part 98, Subpart A, Table A-1 regarding CO_2, CH_4, and N_2O emissions. The natural gas combustion equipment include gas turbines. Emergency generators burn diesel fuels. Potential VOC fugitive emissions are estimated using emission factors from Subpart W, Table W-1A, the final rule issued on 12/23/2011, of 40 CFR Part 98. The potential emissions of SF_6 -containing equipment, such as circuit breakers, are estimated using emission factors from Subpart A, Table A-1, of 40 CFR Part 98. The GHG emissions are estimated both as ton per year (TPY) and as metric ton per year (MTPY). Table 13 lists annual potential facility-wide GHG emissions. The GHG emissions exceed a PTE of 100,000 TPY CO_2e. This facility is a major source of GHG emissions.

Table 13. Facility-Wide Greenhouse Emissions

Emissions Source	Total CO_2e	
	MTPY	TPY
1G1 & 1G2, Gas Turbines, 2,500 MMBTUH (2 Total)	951,773.56	1,049,140.00
EG1 & EG2, Emergency Generators, 43.2 MMBTUH (Total)	28,083.32	30,956.12
Fugitive VOC Emissions	1,444.30	1,592.05
Circuit Breaker	28.22	31.10
Total	**981,329.40**	**1,081,719.27**

SECTION V. BACT REVIEW AND AIR DISPERSION MODELING REVIEW

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 Comanche facility, only CO emissions exceed the applicable PSD SER. The project is driven by NOx reductions needed to achieve BART compliance. There is an inverse relationship between NOx and CO emissions, i.e., procedures which reduce NOx result in increased CO emissions, and vice versa.

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.

Step 1: Identify All Control Technologies

CO Control Technologies

Carbon monoxide is formed as a result of incomplete combustion of fuel. CO emissions from turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors however tend to result in high NO_X emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve lowest NO_X emissions rate possible while also optimizing CO emission rates.

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) indicated that CO emission control methods include exhaust gas cleanup methods such as thermal or catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the turbines.

Good Combustion Practices

According to the EPA's RBLC database, the only recent BACT determination for CO when retrofitting an existing combustion turbine with low NOx burners was use of good combustion practices. Efficient burners can minimize the formation of CO by providing excess oxygen, mixing the fuel thoroughly with air and by employing general good combustion practices. The CO emission limit set for installations with good combustion practices BACT is 0.0785 lb/MMBTU. Good combustion practices also includes limiting the timeframe for startup and shutdown, as indicated in the Section IV, Air Emissions.

Catalytic Oxidation

Another CO control technology for natural gas fired turbines is an oxidation catalyst system. Just like with SCR catalyst technology for NO_X control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation catalyst utilizes the excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. The oxidation is carried out by the following overall reaction:

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$

This reaction is promoted by several noble metal-enriched catalysts at high temperatures. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}. Under ideal operating conditions, this technology can achieve an 80% reduction in CO emissions.

As with SCR, 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.

Catalyst systems are subject to loss of activity over time. Catalyst fouling occurs slowly under normal operating conditions and may be accelerated by even moderate sulfur concentrations in the exhaust gas. The catalyst can be chemically washed to restore its effectiveness, but eventually, irreversible degradation occurs. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5 to 7 year predicted life. Periodic testing of catalyst material is necessary to predict actual catalyst life for a given installation. This system also would be expected to control a small percent (5-40%) of hydrocarbon (VOC) emissions.

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.

Step 2 – Determination of Technical Feasibility of Identified Control 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 which are clearly technically infeasible are identified and not considered further.

Step 3 – Ranking of control technologies by control effectiveness

All identified controlled technologies and their control efficiencies are presented below. The technologies are ranked in order of decreasing effectiveness and the technologies determined as non-feasible are indicated as such.

Ranked Controlled Technologies by Control Efficiency

Pollutant	Control Technology	Control Efficiency (%)	Technical Feasibility
CO	Thermal Oxidation	80-90%	Feasible
	Oxidation Catalyst	60 – 80	Feasible
	Good combustion practices	Base Case	Feasible

Step 4 – Evaluation of the most effective controls

There is no "Bright Line" cost effectiveness threshold for CO; rather, the cost presented for a specific project for control of CO are compared with the cost per ton that have been required of other sources in the same geographical area. For example, a project located in a rural attainment area where dispersion modeling shows less than significant air quality impacts would have a different cost criteria than a project located in or near an urban CO non-attainment area where there is a legitimate need to minimize emissions of CO. It should also be noted that cost effectiveness is a pollutant specific standard. For instance, the cost effectiveness of controlling the more pervasive pollutant NO_X (an acid rain pollutant, a precursor to the formation of regional haze, and a precursor to the formation of ozone) is aptly higher than for the more benign stack level emissions of CO. Areas of CO non-attainment are primarily urban and exceedances of the CO NAAQS are dominated by ground level releases due to automobiles. CO emitted from a power plant stack is quickly dispersed (as shown in the modeling analysis) and is an unstable molecule that naturally is converted to CO_2 in the atmosphere.

The use of an oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10} (and $PM_{2.5}$) emissions. Further, the catalyst bed would create an increased backpressure which would require additional fuel firing to produce the same amount of electricity output, resulting in associated emission increases in other criteria pollutants

The fact that the use of oxidation catalyst for CO reduction would be associated with increase in other emissions, as well as the regional air quality conditions, leads to the determination that combustion controls represent BACT for large gas-fired turbines. There are no expected adverse economic, environmental or energy impacts associated with the use of the proposed control alternative. The proposed CO BACT limit for normal operation is 0.0785 lb/MMBTU.

Step 5 – Selection of BACT

Good combustion practices are the most effective control technology for carbon monoxide emissions and is the only control technology considered that is technically feasible. The Startup/Shutdown BACT is for an older model (1971) combined cycle turbine that is retrofitted with low NOx combustors. The major steps to start up a single combustion turbine are listed below.

Major Steps	Details
1. Start combustion turbine and parallel with grid, load to approximately 7 – 10 GMW.	Time allotted: **1-hour, 30-minutes** Allows turbine to start, ignite and ramp up. Loading to approximately 7 - 10 GMW enables associated boiler to warmup and produce steam.
2. Commence generating steam, warming steam piping and establishing vacuum in condenser while holding combustion turbine load at approximately 7 – 10 GMW.	Time allotted: **1-hour, 45-minutes** Allows steam piping, boiler tubes and steam turbine rotor to heat up within heat-up rate limits. Also allows for the effective draining of condensate from steam piping and turbine casing to prevent water hammer and turbine blade impingement.
3. Load combustion turbine to approximately 45 GMW [1] (below Low NOx operations) in order to meet minimum steam pressure, temperature and flow requirements to start steam turbine.	Time allotted: **1-hour, 30-minutes** Load change rate is limited to allow continued gradual warmup of boiler tubing, main steam piping and steam turbine. Due to age of plant components (approximately 40 years), this operational practice has consistently been adhered to and has contributed to the long life of plant components and thereby reduced cost to utility customers

4. Conduct substation breaker and switch alignment to allow steam turbine to parallel with grid.	Time allotted: **45-minutes** Comanche Power Station is a lean-staffed facility with only one Inside Operator and one Outside Operator who have to conduct all evolutions including turbine/steam plant startup, substation yard operations as well as pure water makeup plant operations to provide makeup water for the steam plant. Time allotted for this step allows for transmission of switching orders from Tulsa Dispatch, verbatim repeat back communications of those orders and pre-evolution safety briefings.
5. Conduct steam turbine safeguard trip testing. Start steam turbine and ramp to one-half of rated speed and allow turbine rotor to soak. Maintain combustion turbine loading at approximately 45 GMW [1] (below Low NOx operations).	Time allotted: **3-hours, 15 minutes** Associated steam turbine safeguard trip testing ensures that several safety mechanisms designed to protect the turbine and associated main condenser, as well as personnel, are functioning properly. The steam turbine components must heat through entirely prior to being placed in service. Inadequate warmup will result in unequal expansion of the turbine casing (stationary component) and turbine rotor (rotating component) which will result in already very close design tolerances between stationary and rotating turbine blades contacting one another resulting in severe damage and/or personnel injury.
6. When steam turbine is warmed adequately, raise to rated speed and parallel with the grid.	Time allotted: 30 **Minutes** Startup ends when pre-mix mode is achieved and plant is released to Production Operations for unlimited operation.

The listed megawatt threshold is dependent on time of year, mainly due to seasonal differences in ambient temperature. Total startup sequence takes nine hours to complete.

The expected amount of emissions with a timeframe representation of startup and shutdown for a single unit is below. When both units are called upon, the units are not started at the same time and the second unit to start has a shortened period at Phase 1 due to an ability to use the heat from the first unit to start.

Carbon Monoxide Emissions per Typical Startup Event (Single Unit)

Phase	**1**	**2**	**3**	**-----**
Description	**Cold Unit to Beginning of Primary Mode**	**Beginning of Primary Mode to Interim Startup Position**	**Interim Startup Position to Pre-mix Mode**	**Total**
lb/MMBTU of CO @ 15% O_2	0.6726	0.1234	0.0336	-----
MMBTU per Hour	266	720	853	-----
Hours per "Phase" for Unit	3.25	5.50	0.25	9
lbs of CO per Startup per unit	581	489	7	1,077

Carbon Monoxide Emissions per Typical Shutdown Event (Single Units)

Phase	**1**	**2**	**3**	**-----**
Description	**Cold Unit to Beginning of Primary Mode**	**Beginning of Primary Mode to Interim Startup Position**	**Interim Startup Position to Pre-mix Mode**	**Total**
lb/MMBTU of CO @ 15% O_2	0.6726	0.1234	0.0336	-----
MMBTU per Hour	266	720	853	-----
Hours per "Phase" for Unit	1.25	1.5	0.25	3
lbs of CO per shutdown per unit	224	133	7	364

Annual Carbon Monoxide Emissions for Startup/Shutdown Event (Single Unit)

Event	**Startup (Cold)**	**Startup (Warm)**	**Shutdown**
Maximum Duration (Hour)	9	6	3
CO Emissions (lbs)	1,077	1,077	364
Annual Emissions (TPY)*	40.38	40.38	13.65

*Based on the limit of 75 cycles of startup/shutdown per year.

In summary, the BACT for turbines in normal operation is listed below.

Summary of Selected BACT for Turbines in Normal Operation

Pollutant	**Control Technology**	**Proposed Permit Limit**
CO	Good combustion practices	0.0785 lb/MMBTU

Regarding the Startup/Shutdown BACT, one of the turbines begins with a cold startup, then, provides heat to the next turbine to allow the next turbine to have a warm startup. The cycle time of startup/shutdown and emissions per event are listed in the table below.

Startups and Shutdowns BACT for Turbines. (Single Unit)

Event	**Maximum Duration (hr)**	**CO (lb/Event)**
Startup (cold)	9	1,077
Startup (warm)	6	1,077
Shutdown	3	364

AIR DISPERSION MODELING REVIEW

A NAAQS analysis for CO was conducted for the facility using EPA's AERSCREEN Version 14147. AERSCREEN is a screening-level air quality dispersion model program developed to conservatively estimate concentrations from a single source. The program estimates the worst-case 1-hr average concentrations based on multiple factors such as meteorology, building downwash, etc. AERSCREEN automatically provides impacts for other averaging periods (3-hr, 8-hr, 24-hr, and annual) using worst-case scaling ratios or averaging time factors.

Since AERSCREEN is incapable of handling more than one discharge point and the discharge point must be circular in characteristic, a "pseudo stack" was created from the four discharges.

This pseudo stack has the same height, discharge area, exit velocity, and imputed exit diameter as a single unit with two 7 foot by 12 foot discharges, since both units are physically and functionally identical. The pseudo stack was centered between the two physical stacks. The EPA's AERSURFACE was utilized to obtain surface characteristics within 1 km of the pseudo stack location. These surface characteristics were used in the AERSCREEN modeling analysis.

Basic Plant Level Input Data for AERSCREEN

Parameter	
Psuedo Stack Coordinates (UTM Zone 14)	561953 3822630
Stack Height (m)	16.76
Stack Diameter (m)	4.46
Plant Grade (ft MSL)	1118
Minimum Ambient Temperature 2009-2013 (K)	254.8
Maximum Ambient Temperature 2009-2013 (K)	318.1
Rural or Urban Characteristic	Rural
Magnetic Declination (degrees)	4.5 East
Turbine Building Height (m)	15.84
Turbine Building Width (m)	33.83
Turbine Building Length (m)	101.8
Angle from Pseudo Stack to Centroid of Building (degrees)	48.5
Distance from Stack to Building Centerline (m)	33.04
Distance to Fenceline from Stack (m)	88.68

The modified units were individually modeled for a variety of operating loads and the following input parameters.

Case	**Load**	**Emission Rate**	**Exit Temperature**	**Exit Velocity**	**1-hr Impact**	**8-hr Impact**
	(MWg)	**(lb/hr)**	**(K)**	**(m/sec)**	**(μg/m^3)**	**(μg/m^3)**
High CO	7	178.91	350	6.52	3,048	2,744
Moderate CO	53	88.85	416	24.75	485	438
Low CO	85	66.92	433	34.11	386	257

An evaluation of a typical startup where both units are to be utilized under the existing plant configuration was conducted. At no time will the two units be operating at the High CO case at the same time. Therefore, it was determined that the resulting maximum modeled impact would be where one unit is operating at the High CO level and one unit is operating at the Moderate CO level. Background concentrations for the 1-hr and 8-hr standards were obtained from the Oklahoma City North CO monitor (40-109-1037). The maximum impacts from the facility under these operating conditions are shown in the table in the next page.

Averaging Period	Unit A (Moderate CO)	Unit B (High CO)	Background Concentration	Combined	NAAQS
	(μg/m^3)	(μg/m^3)	(μg/m^3)	(μg/m^3)	(μg/m^3)
1-hr	485	3,048	1,030	4,563	40,000
8-hr	438	2,744	801	3,983	10,000

As shown in the above table, both the 1-hr and 8-hr maximum impacts are below the applicable NAAQS levels.

SECTION VI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application and listed in OAC 252:100-8, Appendix I, are listed below. Any activities to which a state or federal applicable requirement applies is not insignificant. Record-keeping for activities indicated with "*" is required in the Specific Condition No 12.

1. * Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power or for peaking power service not exceeding 500 hours/year. None identified but may be used in the future. Two power generators are located on site with annual operating hours not exceeding 500 hours/year. However, both generators are subject to 40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart ZZZZ.

2. Gasoline and aircraft fuel handling facilities, equipment, and storage tanks except those subject to New Source Performance Standards and standards in 252:100-37-15, 39-30, 39-41, and 39-48, or with a capacity greater than 400 gallons. Tank T-1 stores fuel oil and has capacity greater than 400 gallons.

3. * Surface coating and degreasing operations which do not exceed a combined total usage of more than 60 gallons/month of coatings, thinners, clean-up solvents, and degreasing solvents at any one emissions unit. Maintenance coating on equipment is required.

4. * Activities that have the potential to emit no more than 5.0 TPY (actual) of any criteria pollutant. All three tanks, T-1, T-2 and T-3, have emissions below 5 TPY.

5. Emissions from crude oil and condensate storage tanks with a capacity of less than or equal to 420,000 gallons that store crude oil and condensate prior to custody transfer as defined by Subpart Kb. None identified but may be conducted in the future.

6. * Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. Tank T-2 has capacity less than 39,894 gallons and stores products having a vapor pressure less than 1.5 psia. Records of capacities and fluids stored shall be required in the permit.

7. Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes. Welding is conducted as a part of routine maintenance and is considered a trivial activity and recordkeeping will not be required in the Specific Conditions.

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

9. Emissions from stationary internal combustion engines rated less than 50 hp output. None identified but may be used in the future.

10. Additions or upgrades of instrumentation or control systems that result in emission increases less than the pollutant quantities specified in OAC 252:100-8-3(e)(1). None identified but may be conducted in the future.

11. Site restoration and/or bioremediation activities of <5 years expected duration. None identified but may be conducted in the future.

12. Hydrocarbon-contaminated soil aeration pads utilized for soils excavated at the facility only. None identified but may be used in the future.

13. Emissions from groundwater remediation wells including but not limited to emissions from venting, pumping, and collecting activities subject to de minimis limits for toxics (OAC 252:100-41-43) and HAP's (112(b) of CAAA90). None identified but may be used in the future.

14. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas. None identified but may be used in the future.

SECTION VII. 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. Compliance with the NAAQS is addressed in the "PSD Review" section.

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 past years.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean

individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant;
- 2 TPY of any one HAP or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule;

Emission limits for the facility are based on the previous Title V permit, No. 2010-496-TVR2 (M-1), the permit application, and the BART application.

OAC 252:100-9 (Excess Emission 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]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Appendix C specifies a PM emission limitation of 0.52 lbs/MMBTU for all equipment at this facility with a heat input rating of 20 Million BTU per hour (MMBTUH) or less. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the following are subject to the requirements of this subchapter. Emission factors shown in Section III (Emissions) above indicate that all Units are in compliance.

Equipment	Maximum Heat Input, (MMBTUH)	Appendix C Emission Limit, (lbs/MMBTU)	Potential Emission Rate, (lbs/MMBTU)
Gas Turbine	1,250	0.20	0.0066*
Diesel Generator	17.6	0.52	0.1000**

* Burn natural gas **Burn No. 2 fuel oil

This subchapter also limits emissions of PM from industrial processes. Per AP-42 factors, there are no significant PM emissions from any other industrial activities at this facility.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that

consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. All of the emission units are subject to this subchapter. The turbines will assure compliance with this rule by ensuring "complete combustion" and utilizing pipeline-quality natural gas as fuel. The diesel-fired generator engines assure compliance with this rule by ensuring "complete combustion."

Continuous monitoring of opacity (COM) is required for fluid bed catalytic cracking unit catalyst regenerators at petroleum refineries and fossil fuel-fired steam generators in accordance with 40 CFR Part 51, Appendix P and any fuel-burning equipment with a design heat input value of 250 MMBTUH or more, that does not burn gaseous fuel exclusively, and that was not in being on or before July 1, 1972, or that is modified after July 1, 1972. 40 CFR Part 51, Appendix P exempts fossil fuel-fired steam generators from the COM requirements when gaseous fuel is the only fuel burned. Since the combustion turbines will only burn natural gas they are exempt from the opacity monitor requirements.

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

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input averaged over 3 hours. The turbines and emergency diesel generators were all constructed prior to the effective date of this subchapter. For liquid fuels, the limit is 0.8 lb/MMBTU heat input, three-hour average. The diesel-fired generator engines utilize diesel fuel with a maximum sulfur content of 0.05 % by weight. This fuel will produce emissions of approximately 0.05 lb/MMBTU, which is well below the allowable emission limitation of 0.8 lb/MMBTU for liquid fuels

For liquid fuels, the limit is 0.8 lb/MMBTU heat input, three-hour average. The diesel-fired generator engines utilize diesel fuel with a maximum sulfur content of 0.05 % by weight. This fuel will produce emissions of approximately 0.05 lb/MMBTU, which is well below the allowable emission limitation of 0.8 lb/MMBTU for liquid fuels.

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 to a three-hour average 0.2 lb of NO_X per MMBTU. For gas turbines, new fuel-burning equipment means any gas turbine constructed after July 1, 1977, or any existing gas turbine that was altered, replaced, or rebuilt after July 1, 1977, resulting in increased emissions of nitrogen oxides. The turbines were constructed prior to July 1, 1977, and have not been altered, replaced, or rebuilt after July 1, 1977, in a manner which would have resulted in an increase in emissions of NO_2.

Listed below is the 3-hr average emission limit (lb/hr) of NO_X for each combustion turbine during normal operation and the equivalent emission rates (lb/MMBTU) based on the maximum heat input, which are below the standard of 0.2 lb/MMBTU. The Backup Diesel Generator is below 50 MMBTUH heat input and is, therefore, not subject to this rule.

Units	MMBTUH	lb/hr	lb/MMBTU
Turbines	1,250	187.50	0.15

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
None of the following affected processes are located at this facility: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Only Part 7 Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia at maximum storage temperature to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The fuel oil tank (T-1) and diesel fuel tank (T-2) are exempt based on vapor pressures below the 1.5 psia level. The condensate tank (T-3) is subject to these requirement.
Part 5 limits the VOC content of coatings from any coating line or other coating operation. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment. No coating operation is located at this facility.
Part 7 requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. The equipment at this location is subject to this requirement.
Part 7 requires all effluent water separator openings which receive water containing more than 200 gallons per day of any VOC, to be sealed or the separator to be equipped with an external floating roof or a fixed roof with an internal floating roof or a vapor recovery system. No effluent water separators are located at this facility.

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 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
Final total facility emissions are greater than the PSD major source threshold of 250 TPY for regulated pollutants, NOx and CO. The facility is considered an existing major source for PSD and any future emission increases must be evaluated for PSD if they exceed a significance emission level (40 TPY for NOx, 100 TPY for CO, 40 TPY for VOC, 40 TPY for SO_2, 25 TPY for TSP, 15 TPY for PM_{10}, 10 TPY for $PM_{2.5}$, 0.6 TPY for Pb, and 10 TPY for TRS). CO emission increase is greater than 100 TPY and a PSD review has been completed in Section V.

NSPS, 40 CFR Part 60 [Not Applicable]
Subparts D, Da, Electric Utility Steam Generating Units. Subpart D and Da regulates each steam generating unit that commences construction, modification, or reconstruction after August 17, 1971, and September 18, 1978, respectively. The units at this plant were constructed prior to the August 17, 1971, and September 18, 1978, applicability dates of these Subparts. Therefore, these subparts are not applicable.
Subparts K, Ka, Kb, VOL Storage Vessels. Subpart Kb regulates hydrocarbon storage tanks larger than 19,813 gallons capacity and built after July 23, 1984. The three significant storage tanks (T-1, T-2, and T-3) are all exempt based on capacity below the regulated threshold (T-2 and T-3) and/or on construction (T-1 and T-3) prior to the effective dates.
Subpart GG, Stationary Gas Turbines. Subpart GG affects stationary gas turbines which commenced construction, reconstruction, or modification after October 3, 1977, with a heat input at peak load of greater than or equal to 10 MMBTUH based on the lower heating value of the fuel. The two gas turbines in this facility are not subject to this subpart because they were constructed in May 1971, which is prior to the effective date, October 3, 1977, and since May 1971, they have not been modified or reconstructed as defined in NSPS Subpart A.
Subpart KKKK, Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBTUH, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Stationary combustion turbines regulated under this subpart are exempt from the requirements of Subpart GG of this part. The two gas turbines have original manufacture dates

(May 1971) prior to February 18, 2005 and since May 1971, they have not been modified or reconstructed as defined in NSPS Subpart A.

NESHAP, 40 CFR Part 61 [Not Applicable]
Based on use of EPA's AP-42 emission factors, there are only trace potential emissions of the following regulated pollutants: arsenic, beryllium, benzene, and mercury. No potential emissions were determined to exist, using AP-42 emission factors, for the following regulated pollutants: asbestos, coke oven emissions, radionuclides or vinyl chloride.

Subpart J, Equipment Leaks of Benzene, only applies to process streams, which contain more than 10% benzene by weight. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.
Subparts N, O, and P (Inorganic Arsenic from Glass Manufacturing, Primary Copper Smelters and Arsenic Trioxide and Metallic Arsenic Production). Electric generating facilities are not an affected source under any of these subparts.
Subparts J, Y, BB, and FF (Benzene Fugitives, Benzene Storage, Benzene Transfer, and Benzene Waste). Electric generating facilities are not an affected source under any of these subparts.
Subparts C and D (Beryllium and Beryllium Rocket Motor Firing). Electric generating facilities are not an affected source under either of these subparts.
Subpart E (Mercury). Electric generating facilities are not an affected source under this subpart.

NESHAP, 40 CFR Part 63 [Subpart ZZZZ Applicable]
Subpart YYYY, Stationary Combustion Turbines. This subpart affects turbines that are located at a major source for hazardous air pollutants (HAPs) emissions such as formaldehyde, toluene, benzene, and acetaldehyde. The stationary combustion turbine category is divided into eight subcategories, including lean premix gas-fired turbines, diffusion flame gas-fired turbines, diffusion flame oil-fired turbines, emergency turbines, turbines with a rated peak power output of less than 1.0 megawatt (MW), turbines burning landfill or digester gas, and turbines located on the North Slope of Alaska. HAP emission calculations have shown that the facility is a minor source of HAPs. This subpart does not apply.
Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). On January 18, 2008, the EPA published a final rule that promulgates standards for new and reconstructed engines. This subpart affects any existing, new, or reconstructed stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand. The following table differentiates existing, new, or reconstructed units based on their construction dates.

	Construction/Reconstruction Dates	
	Engines >500 hp	**Engines ≤ 500hp**
Existing Unit		
Located at Major HAP Source	Before 12/19/02	Before 6/12/06
Located at Area HAP Source	Before 6/12/06	
	Construction/Reconstruction Dates	
	Engines >500 hp	**Engines ≤ 500hp**
New or Reconstructed Unit		
Located at Major HAP Source	On and After 12/19/02	On and After 6/12/06
Located at Area HAP Source	On and After 6/12/06	

The following table lists the status of each emergency generator engine at this facility:

EU ID#	Make/Model	Size (HP)	Construction Date	Status
EG1	General Motors/MP-36	2,700	April 1962*	Existing
EG2	General Motors/MP-36	2,700	April 1962*	Existing

*These two units were moved to Comanche Station in 1990.

Both emergency generator engines fall under existing units located at an area HAP source category. On March 3, 2010, EPA finalized additional requirements for existing stationary CI RICE located at area sources. As emergency CI engines larger than 500-hp located at a minor source of HAP, both engines here are subject to the additional requirements. A summary of these requirements are shown below.

Engine Category	Normal Operation** @ 15% O_2
Existing Emergency CI & Black Start CI*	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.

*Black Start engine means an engine whose only purpose is to start up a combustion turbine.

** 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 performance test when the engine is started up again.

CAM, 40 CFR Part 64 [Not Applicable]

Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY

The facility is subject to 40 CFR 75 (Acid Rain) requirements on the two combustion turbines. These two units are exempt from CAM requirements since there are no active control devices to lower emissions.

Chemical Accident Prevention Provision, 40 CFR Part 68 [Not Applicable]

The facility does not process or store chlorine gas. The facility does process or store hydrogen gas on site, but not more than the applicable threshold limit of 10,000 pounds (Section 112r of the Clean Air Act 1990 Amendments). More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
A separate Acid Rain Permit No. 2009-436-ARR2 was issued on March 8, 2010. This permit satisfies the permit requirements.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
Permit No. 2009-436-ARR2 contains SO_2 initial allowances as published in 40 CFR 73.10. However, allowances can be traded, bought, and sold. Therefore, the actual allowances held by an affected unit may change. But, the change will not necessitate a revision to the Acid Rain 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 issued a certification for Units 1G1 and 1G2 on February 5, 1997.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and F 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 IX. COMPLIANCE

Testing

The facility continues to monitor emissions as required by 40 CFR 75 (acid rain) and conducts annual testing of the equipment for verification. Air Quality observations have shown that testing of the continuous emission monitors has been conducted properly. CEMs data is submitted to Headquarters EPA on a quarterly basis as required by the Acid Rain Program.

Tier Classification and Public Review

This application has been classified as Tier II based upon a request for construction permit of a Title-V emission source. Public review of the application and permit are required. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the real property.

The applicant published the "Notice of Filing a Tier II Permit Application" in *The Lawton Constitution*, a daily newspaper printed and published in the City of Lawton, in Comanche County, on August 15, 2014. The notice stated that the application was available for public review at the Lawton Public Library, 110 SW 4th Street, Lawton, Oklahoma 73501 or at the Air Quality Division's Main Office in Oklahoma City, Oklahoma 73101. The applicant published the "Notice of Filing a Tier II Draft Permit" in *The Lawton Constitution*, a daily newspaper printed and published in the City of Lawton, in Comanche County, on August 25, 2015. The notice stated that the draft permit was available for public review at the Lawton Public Library, 110 SW 4th Street, Lawton, Oklahoma 73501 or at the Air Quality Division's Main Office in Oklahoma City, Oklahoma 73101. The draft permit was also available for public review on the Air Quality Section of the DEQ Web Page at *http://www.deq.state.ok.us*. This permit was approved for concurrent public and EPA review. This facility is not located within 50 miles of the border of Oklahoma and any other state. Public review period started on August 25, 2015, and ended on September 25, 2015. No comments were received from the public. Since there were no comments received from the public, then, the draft permit was actually deemed the proposed permit for EPA review. EPA review period started on August 21, 2015, and ended on October 5, 2015. No comments were received from the EPA Region VI. Information on all permit actions is available for review by the public in the Air Quality Section of DEQ Web Page: *http://www.deq.state.ok.us.*

Fees Paid

Part 70 construction permit modification fee of $5,000 was received by AQD on August 18, 2014.

SECTION X. SUMMARY

The facility has demonstrated the ability to comply with the requirements of the several air pollution control rules and regulations. Ambient air quality standards are not threatened at this site. There are no other 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

American Electric Power (AEP) **Permit Number 2010-496-C (M-2) PSD**
Public Service Company of Oklahoma (PSO)
Comanche Power Station

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on August 18, 2014, and supporting/supplemental information received on August 27, 2014, December 12, 2014, July 20, 2015, July 23, 2015, August 10, 2015, and September 21, 2015. The Evaluation Memorandum dated October 6, 2015, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

1. Points of emissions and emissions limitations are detailed below. [OAC 252:100-8-6(a)]

EUG 2: Combustion Turbines are no longer considered "grandfathered" (pre-May 31, 1972 construction) equipment due to installation of DLNB.

EUG 2 Combustion Gas Turbines

EU ID#	Point ID#	EU Name/Model	MMBTUH	MW	Serial No.	Const. Date
1G1	1G1	Westinghouse /W-501B	1,250	94	17A8012	May 1971
1G2	1G2	Westinghouse /W-501B	1,250	94	17A8014	May 1971

Emission limits and standards for Emission Units (EUs) 1G1 and 1G2 include but are not limited to the following:

	NOx		CO		SO_2		PM_{10}	
EU	lb/hr***	TPY****	lb/hr***	TPY****	lb/hr***	TPY****	lb/hr***	TPY****
Unit 1G1	187.50*	824.33**	98.13*	439.67**	4.00	17.52	8.25	36.14
Unit 1G2	187.50*	824.33**	98.13*	439.67**	4.00	17.52	8.25	36.14

* Normal operation only, does not including startup/shutdown periods
** Including startup/shutdown periods, 75 periods per year
******* Three-hour rolling average, based on the arithmetic average of three contiguous one-hour operating periods.
******** Twelve-month rolling total

NOx Emissions

Regarding the NOx emissions, the turbines in EUG 2 (Units 1G1 and 1G2) are subject to the Best Available Retrofit Technology (BART) requirements of 40 CFR Part 51, Subpart P, and shall comply with all applicable requirements including but not limited to the following:
[40 CFR §§ 51.300-309 & Part 51, Appendix Y]

a. Affected facilities. Units 1G1 and 1G2 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.

b. Each existing affected facility shall install and operate the SIP approved BART as expeditiously as practicable but no later than January 27, 2017.
c. Issuance of this permit shall indicate that the permittee has met its obligation to apply for and obtain a PSD construction permit prior to modification of the turbines.
d. The permittee shall equip the affected facilities with Dry Low-NOx Burners, as determined in the submitted BART analysis, to reduce emissions of NOx to below the emission limits listed in paragraph f. below.
e. The permittee shall maintain the combustion controls (Dry Low-NOx burners) and establish procedures to ensure the controls are properly operated and maintained.
f. Within 60 days of achieving maximum power output from each affected facility, after modification or installation of BART, not to exceed 180 days from initial start-up of the affected facility and no later than January 27, 2017, the permittee shall comply with the following emission limits:

EU ID#	Point ID#	NOX Emission Limit	Averaging Period
1G1	1G1	0.15 lb/MMBTU	30-day rolling
1G2	1G2	0.15 lb/MMBTU	30-day rolling

g. Within 60 days of achieving maximum power output from each turbine, after modification of the turbines, not to exceed 180 days from initial start-up, the permittee shall conduct performance testing and furnish a written report to Air Quality. Such report shall document compliance with BART emission limits for the affected facilities.

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

(i). 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.
(ii). The permittee shall also provide advanced notice of the actual test date to AQD.

CO Emissions

Following installation of DLNB, CO emissions shall not exceed 0.0785 lb/MMBTU, 3-hour average. During startups and shutdowns alternate emission limits apply to the turbines. Startup events shall not exceed nine (9) hours per turbine and 1,077 lbs of CO per turbine per event. Shutdown events shall not exceed three (3) hours per turbine and 364 lbs of CO per turbine per event. In testing situations required to fulfill North American Electric Reliability Corporation (NERC) mandates, the unit is not required to achieve pre-mix mode. The following definitions apply as well as the emission limitations for each turbine listed in the next page.

Startup: Startup for each gas turbine begins when fuel is supplied to the Gas Turbine and combustion is initiated. Startup ends when the gas turbine reaches pre-mix mode (as directed by the control system).
Shutdown: Shutdown begins when the turbine exits pre-mix mode for the purpose of shutting down. Shutdown ends with the termination of fuel flow to the turbine.
Cold Start: A startup beginning more than 24 hours after the same unit shutdown.
Warm Startup: A startup beginning less than 24 hours after the same unit shutdown.

Event	Maximum Duration (hr)	CO (lb/Event)
Startup (cold)	9	1,077
Startup (warm)	6	1,077
Shutdown	3	364

Compliance with emission limits of CO shall be demonstrated with an initial performance test by the permittee using the following test methods specified in 40 CFR Part 60:

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 or 10B: Determination of Carbon Monoxide Emissions from Stationary Sources.

Performance testing shall be conducted while the facility is operating within 10% of the maximum rate at which operating permit authorization is sought.

EUG 3: Tank VOC emissions are insignificant based on existing equipment and do not have a specific limitation.

Point	Contents	Capacity	
		Barrels	Gallons
T-1	Fuel Oil	50,000	2,100,000
T-2	Diesel Fuel	380	16,000
T-3	Condensate	400	16,800

EUG 4: Emergency generators operate less than 500 hours per year. Therefore, there are currently no emission limitations. Standards of NESHAP Subpart ZZZZ apply to these units.

EU ID#	Point ID#	Make/Model	hp	Serial #	Const. Date
EG1	EG1	General Motors/MP-36	2,700	63076	April 1962*
EG2	EG2	General Motors/MP-36	2,700	63075	April 1962*

*These two units were moved to Comanche Station in 1990.

EUG 5: Fugitive emissions at this facility are de minimis and do not have a specific limitation.

2. Upon issuance of an operating permit, 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. Each turbine at the facility shall have a permanent identification plate attached which shows the make, model number, and serial number. [OAC 252:100-43]

4. The fuel-burning equipment, such as turbines, shall be fired with pipeline grade natural gas except for the diesel fired emergency generators. Compliance can be shown by the following methods: for pipeline grade natural gas, a current gas company bill; for other gaseous fuel, a current lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Emergency generators are limited to firing low sulfur diesel with a sulfur content of 0.05% by weight as required by NSPS and NESHAP. Compliance can be shown by the following methods: supplier's latest delivery/shipment ticket(s). Compliance shall be demonstrated at least once every calendar year. [OAC 252:100-31]

5. The facility is subject to the Acid Rain Program and shall comply with all applicable requirements including the following:

   a. SO_2 actual emissions equal or less than allowances held.
   b. Report quarterly emissions to EPA per 40 CFR 75.
   c. Conduct RATA tests per 40 CFR 75.
   d. Maintain a QA/QC plan for the monitoring system.

6. Replacement (including temporary periods of six months or less for maintenance purposes), of internal combustion engines/turbines with emissions limitations specified in this permit with engines/turbines of lesser or equal emissions of each pollutant (in lbs/hr and TPY) are authorized under the following conditions. [OAC 252:100-8-6 (f)]

   a. The permittee shall notify AQD in writing not later than 7 days in advance of the startup of the replacement engine(s)/turbine(s). Said notice shall identify the old engine/turbine and shall include the new engine/turbine make and model, horsepower rating, fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lb/hr, and TPY) at maximum horsepower for the altitude/location.

   b. Quarterly emissions tests for the replacement engine(s)/turbine(s) shall be conducted to confirm continued compliance with NOx and CO emissions limitations. A copy of the first quarter testing shall be provided to AQD within 60 days of start-up of each replacement engine/turbine. The test report shall include the engine/turbine fuel usage, stack flow (ACFM), stack temperature (°F), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location.

   c. Replacement equipment and emissions are limited to equipment and emissions which are not a modification under NSPS, NESHAP, or a significant modification under PSD. For existing PSD facilities, the permittee shall calculate the PTE or the net emissions increase resulting from the replacement to document that it does not exceed significance levels and submit the results with the notice required by a. of this Specific Condition.

   d. Engines installed as allowed under the replacement allowances in this Specific Condition that are subject to 40 CFR Part 63, Subpart ZZZZ and/or 40 CFR Part 60, Subpart JJJJ shall comply with all applicable requirements.

7. The permittee shall comply with all applicable requirements of the NESHAP (40 CFR Part 63) for Stationary Reciprocating Internal Combustion Engines (RICE), Subpart ZZZZ, for each affected engine including but not limited to:

[40 CFR 63.6580 through 63.6675]

<u>What This Subpart Covers</u>

a. § 63.6580 What is the purpose of subpart ZZZZ?
b. § 63.6585 Am I subject to this subpart?
c. § 63.6590 What parts of my plant does this subpart cover?
d. § 63.6595 When do I have to comply with this subpart?

<u>Emission and Operating Limitations</u>

e. § 63.6603 What emission limitations, operating limitations, and other requirement must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?
f. § 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

<u>General Compliance Requirements</u>

g. § 63.6605 What are my general requirements for complying with this subpart?

<u>Testing and Initial Compliance Requirements</u>

h. § 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing 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 stationary RICE located at an area source of HAP emissions?
i. § 63.6615 When must I conduct subsequent performance tests?
j. § 63.6620 What performance tests and other procedures must I use?
k. § 63.6625 What are my monitoring, installation, collection, operation, maintenance, and other requirements?
l. § 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

<u>Continuous Compliance Requirements</u>

m. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
n. § 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

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

o. § 63.6645 What notifications must I submit and when?
p. § 63.6650 What reports must I submit and when?
q. § 63.6655 What records must I keep?
r. § 63.6660 In what form and how long must I keep my records?

<u>Other Requirements and Information</u>

s. § 63.6665 What parts of the General Provisions apply to me?
t. § 63.6670 Who implements and enforces this subpart?
u. § 63.6675 What definitions apply to this subpart?

8. The permittee shall keep operation and maintenance (O&M) records for those "grand-fathered" emission units identified in EUG 2 and EUG 3, which have not been modified and for those replacement or additional engines/turbines which do not conduct quarterly testing.

Such records shall at a minimum include the dates of operation, and maintenance, type of work performed, and the increase, if any, in emissions as a result. [OAC252:100-8-6(a)(3)(B)]

9. The permittee shall maintain records of operations as listed below. These records shall be maintained on site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-43]

   a. For the fuel(s) burned, the appropriate document(s) as described in Specific Condition No. 4.
   b. O&M records for each turbine.
   c. Usage of natural gas and diesel fuel (monthly and 12-month rolling total).
   d. Operating hours of each emergency generator (monthly and 12-month rolling total).
   e. Operating hours for each turbine (monthly and 12-month rolling total).
   f. RATA test results.
   g. Records as required by 40 CFR Part 63, NESHAP, Subpart ZZZZ.

10. The following records shall be maintained on site to verify insignificant activities. Insignificant activities which are also trivial activities do not require record keeping. [OAC 252:100-43]

   a. For storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature: Records of capacity of the tanks, and contents.
   b. Surface coating and degreasing operations which do not exceed a combined total usage of more than 60 gallons/month of coatings, thinners, clean-up solvents, and degreasing solvents at any one emissions unit. Amount of solvent/coatings used (annual total).
   c. For activities (except for trivial activities) that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant: The type of activity and the amount of emissions or a surrogate measure of the activity (annual total).

11. No later than 30 days after each anniversary date of the issuance of the original Title V operating 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)]

   a. Following submittal of an Annual Compliance Certification for the period of June 21 to April 1, April 1 of each year may be used as the anniversary date for Annual Compliance Certifications.
   b. Following submittal of a Semi-Annual Monitoring Report either for the period of June 22 to September 30 or for the period of December 22 to April 1, April 1 of each year may be used as the anniversary date for Semi-Annual Monitoring Reports.

12. Within 180 days of operational start-up of the DLNB, the permittee shall submit an application for a Part 70 operating permit along with the following information, and noting any changes in operation from this construction permit application.

   a. Stack testing of turbines.

Mr. William Hildeson
Senior Engineer, Air Quality Services
AEP Environmental Services-West
American Electric Power (AEP)
1201 Elm Street, Suite 800
Dallas, Texas 75202

SUBJECT: Title V Construction Permit **No. 2010-496-C (M-2) PSD**
AEP-Public Service Company of Oklahoma (PSO)
Comanche Power Station
Facility ID: 0211
Section 23, Township 1N, Range 11W
Lawton, Comanche County, Oklahoma

Dear Mr. Hildeson:

Enclosed is the permit authorizing construction/operation of the referenced facility above. Please note that this permit is issued subject to standard 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 we may be of further service, or you have any questions about this permit, please contact me, mark.chen@deq.ok.gov, or at (405) 702-4196.

Sincerely,

Mark Chen, P.E., Senior Environmental Engineer
New Source Permits Section
AIR QUALITY DIVISION

Enclosure

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT
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, 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), (C)(v), 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)-(iv)]

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:

(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).

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

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:

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

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:
(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. [OAC 252:100-25]

(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:

(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. [40 CFR 82, Subpart A]

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:

(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. [40 CFR 82, Subpart F]

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.

PART 70 PERMIT

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

Permit No. 2010-496-C (M-2) PSD

AEP - Public Service Company of Oklahoma (PSO),

having complied with the requirements of the law, is hereby granted permission to construct/modify the Comanche Power Station located in Section 23, Township 1N, Range 11W, Comanche County, Oklahoma, subject to Major Source Standard Conditions dated July 21, 2009, and Specific Conditions, both attached.

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

Eddie Terrill	**Date**
Division Director, Air Quality Division	

DEQ Form #100-890 **Revised 10/20/06**