OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **December 6, 2001**

TO: Dawson Lasseter, P.E., Chief Engineer, Air Quality

THROUGH: Phillip Fielder, P.E., New Source Permits Unit
Richard Kienlen, P.E., Existing Source Permits Unit

THROUGH: Peer Review

FROM: Eric L. Milligan, P.E., New Source Permits Unit

SUBJECT: Evaluation of Permit Application No. **2001-157-C (PSD)**
Duke Energy Stephens, L.L.C.
Stephens Energy Facility
Section 32-T1S-R7W, Stephens County

SECTION I. INTRODUCTION

Duke Energy Stephens, L.L.C. submitted an application for a construction permit on July 10, 2001. The proposed merchant power plant (SIC Code 4911) will consist of two combined cycle gas turbine generators and two heat recovery steam generators with duct burners producing a nominal total of 620 MW. Since the facility will have emissions in excess of the Prevention of Significant Deterioration (PSD) threshold level (100 TPY), the application has been determined to require Tier III public review.

SECTION II. FACILITY DESCRIPTION

The proposed facility will consist of two natural gas-fired combined cycle combustion turbine generators with duct burners, two heat recovery steam generators, a common steam turbine generator, a natural gas-fired auxiliary boiler, a backup diesel generator, a diesel fire water pump, and cooling tower. The facility will also include a balance of plant equipment and systems such as natural gas metering systems, handling systems, instrumentation and control systems, water treatment, storage and handling, transformers, and administration and warehouse/maintenance buildings.

Each of the gas turbines will be a General Electric PG7241(FA) combustion turbine with a nominal heat input of 1,701 MMBTU/H (LHV). The two heat recovery steam generators (HRSGs) will take advantage of the hot exhaust gases from the combustion turbines and duct burners (565 MMBTU/H each) (LHV) to produce high pressure steam, which will then power the steam turbine to produce electricity.

Selective catalytic reduction (SCR) will be applied to the exhaust stream by injecting ammonia downstream from the duct burners and upstream of a catalyst bed. This causes most NO_X to be converted to nitrogen and water vapor, but allows some emissions of ammonia. This process will be described in greater detail in the BACT analysis later in this memorandum.

The facility will utilize an auxiliary boiler with a rated heat input of 33 MMBTU/H (LHV) to augment the steam turbine start-up. The boiler will fire natural gas exclusively and be limited to an annual operation of 6,000 hours.

The backup diesel generator will be used as a backup system in the event that there is a power outage. The backup diesel generator is rated at 500 kW. The diesel fire water pump is rated at 200 BHP. These internal combustion engines will be limited to a maximum annual operation of 100 hours each.

The facility will utilize one cooling tower consisting of approximately 10 cells. The cooling tower will provide cooling water for condensing the steam turbine exhaust.

SECTION III. SCOPE OF REVIEW AND EMISSIONS

Since the facility will exceed the 100 TPY PSD threshold for NO_X, CO, and PM_{10}, the project is subject to full PSD review. Tier III public review, best available control technology (BACT), and ambient impacts analyses are also required.

The project is also subject to NSPS Subpart GG for combustion turbines. Numerous Oklahoma Air Quality rules affect the new turbines, duct burners, backup diesel generator, diesel fire water pump engine, and auxiliary boiler as fuel-burning equipment, rules including Subchapters 19, 25, 31, 33, and 37. Pollutants emitted in minor quantities were evaluated for all pollutant-specific rules, regulations and guidelines.

This project involves a number of emission points. Emissions are generated by combustion at the turbines, at the duct burners, at the auxiliary boiler, and to a much smaller extent at the backup diesel generator and fire water pump. Each HRSG stack exhausts combustion emissions from the duct burner and related turbine. Very small emissions of VOC are expected from the diesel storage tanks. Ammonia is supplied to the SCR process in amounts slightly above the stoichiometric requirement, so there will be some emissions of ammonia, called “ammonia slip,” in the exhaust.

A. Criteria Pollutants

Turbine and duct burner emissions are based on SCR manufacturer's data (NOx: 3.5 ppmvd @ 15% O_2 for both the turbine alone and the turbine with the duct burner firing; CO: 10 ppmvd @ 15% O_2 for the turbine alone, 16 ppmvd @ 15% O_2 for the turbine with duct burner firing; VOC: 1.4 ppmvw @ 10.4% O_2 for the turbine alone, 9.7 ppmvw @ 10.4% O_2 for the turbine with duct burner firing; SO_2: emissions are based on natural gas with a sulfur content of 2 grains/100 SCF; PM_{10}: 19 lb/hr for each turbine alone, 34.5 lb/hr for each turbine with the duct burner firing; ammonia slip: 10 ppmvd @ 15% O_2 for both the turbine alone and the turbine with the duct burner firing;) and continuous operation. Emissions from the auxiliary boiler are based on manufacturer's data and 6,000 hours/year of operation. Emissions from the backup diesel generator are based on manufacturer's data and 100 hours/year of planned operation. Emissions from the diesel fire water pump are based on AP-42 (10/96), Section 3.3 and 100 hours/year of planned operation.

Turbine and Duct Burner Emissions

Pollutant	Single Turbine		Turbine with Duct Burner		Two Turbines with Duct Burners	
	lb/hr*	TPY	lb/hr*	TPY	lb/hr*	TPY
NO_X	24.0	96.9	32.0	130.8	63.9	261.5
CO	41.7	168.6	88.1	364.4	176.1	728.8
VOC	3.0	12.3	20.9	86.3	41.8	172.6
SO_2	11.0	43.8	14.5	58.7	29.0	117.4
PM_{10}	19.0	83.2	34.5	148.9	69.0	297.8
Lead	0.0	0.0	<0.001	0.001	0.001	0.001

* - lb/hr emissions are based on the worst case or the maximum hourly emissions.

Calculated Facility Wide Emissions

Pollutant	Two CTGs w/ Duct Burners		Auxiliary Boiler		Backup(1) Diesel Generator		Diesel(1) Fire Water Pump		Cooling(2) Tower		Total Maximum (3) Annual Emissions	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
NO_X	63.9	261.5	1.7	5.0	10.2	2.6	6.2	1.6	---	---	82.0	270.7
CO	176.1	728.8	2.8	8.4	12.6	3.2	1.3	0.3	---	---	192.8	740.7
VOC	41.8	172.6	0.5	1.6	1.5	0.4	0.5	0.1	---	---	44.3	174.7
SO_2	29.0	117.4	0.2	0.6	0.3	0.1	0.4	0.1	---	---	29.9	118.2
PM_{10}	69.0	297.8	0.3	1.0	0.6	0.2	0.6	0.2	1.2	5.1	71.7	304.3
Lead	<0.01	<0.01	---	---	---	---	---	---	---	---	<0.01	<0.01

(1) Backup Diesel Generator (500 kW) and Diesel Fire Water Pump (200 hp) are insignificant sources by definition in Appendix I of OAC 252:100.

(2) Cooling towers are a trivial source as per Appendix J of OAC 252:100.

(3) "Total Emissions" includes the total emissions for two turbines, two duct burners, one auxiliary boiler, one backup diesel generator, one diesel fire water pump, and one cooling tower.

B. Hazardous Air Pollutants (HAPs) and Toxic Air Contaminants (TACs)

Toxic emissions from the turbines are based on AP-42 (4/2000), Table 3.1-3, except formaldehyde, sulfuric acid mist, and ammonia emissions. Formaldehyde emissions are derived from the EPA database used to establish emission factors for Section 3.1. Ammonia emissions are based on manufacturer's data (10 ppmvd @ 15% O_2). Sulfuric acid mist emissions are based on the applicant's assumption that 10% of SO_2 will be converted to SO_3 and 100% of SO_3 will be converted to H_2SO_4. Toxic emissions from the duct burners and auxiliary boiler were calculated using AP-42 (7/98), Table 1.4-3 and 1.4-4. Only emissions greater than 1.0E-3 (lb/hr and TPY) are listed.

HAPs and TACs From Combustion Units
(Turbines, Duct Burners, and Auxiliary Boiler)

		Toxic	De Minimis Levels		Emissions	
Pollutant	**CAS #**	**Category**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Ammonia	7664417	C	5.6	6.0	**74.60**	**309.23**
*1,3-Butadiene	106990	A	0.57	0.60	0.002	0.007
*Acetaldehyde	75070	B	1.1	1.2	0.150	0.656
*Acrolein	107028	A	0.57	0.60	0.024	0.105
*Arsenic	7440382	A	0.57	0.60	0.000	0.001
Barium	7440393	B	1.1	1.2	0.006	0.024
*Benzene	71432	A	0.57	0.60	0.052	0.229
*Cadmium	7440439	A	0.57	0.6	0.001	0.006
*Chromium	7738945	A	0.57	0.6	0.002	0.008
Copper	7440508	B	1.1	1.2	0.001	0.005
*Dichlorobenzene	541731	B	1.1	1.2	0.002	0.007
*Ethylbenzene	100414	C	5.6	6.0	0.120	0.525
*Formaldehyde	50000	A	0.57	0.60	**1.089**	**4.763**
*Hexane	110543	C	5.6	6.0	0.034	0.147
Molybdenum	7439987	C	5.6	6.0	0.002	0.006
*Naphthalene	91203	B	1.1	1.2	0.006	0.025
*Nickel	7440020	A	0.57	0.60	0.003	0.011
*PAHs	**	A	0.57	0.60	0.008	0.036
Pentane	109660	C	5.6	6.0	**3.263**	**14.164**
*Propylene Oxide	75569	A	0.57	0.60	0.109	0.475
Sulfuric acid	7664939	A	0.57	0.6	**4.815**	**20.643**
*Toluene	108883	C	5.6	6.0	0.264	1.156
Vanadium	7440622	A	0.57	0.60	0.003	0.013
*Xylene	1330207	C	5.6	6.0	0.240	1.050
Zinc	7440666	C	5.6	6.0	0.036	0.157

* HAPs ** total group **Bold** = above de minimis levels

The cooling water toxic emission rates in the table below were based upon the toxic concentrations in the circulating water at the Arcadia Power Plant (Permit No. 2000-090-C (PSD)). These concentrations were derived from the concentrations in the raw feed water at that plant. Since the Stephens Energy Facility is half the size of the Arcadia facility, there is about 4 MGD less water to process, and since Arcadia's emissions were determined to be under the de minimis levels, this facility is assured to be in compliance with the de minimis levels. In addition, the Stephens Energy Facility water supply will be of equivalent or better water quality than the Arcadia Power Plant.

Hazardous Air Pollutants (HAPS)
From Permit No. 2000-090-C (PSD) Cooling Water Towers

	Toxic	**De Minimis Levels**		**Emissions**	
Pollutant	**Category**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Antimony	B	1.1	1.2	0.0012	0.0053
Arsenic	A	0.57	0.6	0.0002	0.0009
Beryllium	A	0.57	0.6	0.0001	0.0004
Cadmium	A	0.57	0.6	1.63×10^{-5}	0.00007
Chromium(1)	A	0.57	0.6	0.0002	0.0009
Copper	B	1.1	1.2	0.0002	0.0009
Lead(2)	(2)	N/A	N/A	0.0001	0.0004
Mercury	A	0.57	0.6	4.08×10^{-6}	0.00002
Nickel	A	0.57	0.6	0.0002	0.0009
Selenium	C	5.6	6.0	5.10×10^{-5}	0.0002
Silver	B	1.1	1.2	4.08×10^{-5}	0.00018
Thallium	A	0.57	0.6	0.0002	0.0009
Zinc	C	5.6	6.0	0.002	0.009

(1) All chromium is assumed to be hexavalent. (2) Lead is regulated by NAAQS.

For emissions of each pollutant that exceeded a respective de minimis level, modeling was required to demonstrate compliance with the respective Maximum Acceptable Ambient Concentration (MAAC). SCREEN3 modeling was conducted for each toxic and indicated the facility would be in compliance with each MAAC.

Pollutant	**CAS #**	**MAAC ($\mu g/m^3$)**	**Emissions (lb/hr)**	**Estimated Impact ($\mu g/m^3$)**
Ammonia	7664417	1,742	74.6	10.8
Formaldehyde	50000	12	1.1	0.1
Pentane	109660	35,000	3.3	1.1
Sulfuric Acid	7664939	10	4.8	0.7

SECTION IV. PSD REVIEW

As shown in the emission summary below, the proposed facility will have potential emissions above the PSD significance levels for NOx, CO, VOC, SO_2, and PM_{10} and are reviewed below.

EMISSIONS INCREASES COMPARED TO PSD LEVELS OF SIGNIFICANCE

Pollutant	Emissions, TPY	PSD Levels of Significance, TPY	PSD Review Required?
NOx	271	40	Yes
CO	741	100	Yes
VOC	175	40	Yes
SO_2	118	40	Yes
PM/PM_{10}	304	25/15	Yes
H_2SO_4	21	7	Yes

Full PSD review of emissions consists of the following:

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

A. Best Available Control Technology (BACT)

The pollutants subject to review under the PSD regulations, and for which a BACT analysis is required, include nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), sulfur dioxide (SO_2), particulates less than or equal to 10 microns in diameter (PM_{10}), and sulfuric acid (H_2SO_4). The BACT review follows the "top-down" approach recommended by the EPA.

The emission units for which a BACT analysis is required include the combustion turbines, duct burners, backup diesel generator, diesel fire water pump and cooling tower, which will be discussed in this order. Economic as well as energy and environmental impacts are considered in a BACT analysis. The EPA-required top-down BACT approach must look not only at the most stringent emission control technology previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc. Duke Energy Stephens identified these technologies and emissions data through a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as EPA's NSR and CTC websites, recent DEQ BACT determinations for similar facilities, and vendor-supplied information.

NOx BACT Review

1. Combustion Turbines and Duct Burners

a) Identification of Control Techniques

Nitrogen Oxides (NO_X) are formed during the fuel combustion process. There are three types of NO_X formations: thermal NO_X, fuel-bound NO_X, and prompt NO_X. Thermal NO_X is created by the high temperature reaction in the combustion chamber between atmospheric nitrogen and oxygen. The amount that is formed is a function of time, turbulence, temperature, and fuel to air ratios within the combustion flame zone. Fuel-bound NO_X is created by the gas-phase oxidation of the elemental nitrogen contained within the fuel. Its formation is a function of the fuel nitrogen content and the amount of oxygen in the combustion chamber. Fuel NO_X is temperature-dependent to a lesser degree; at lower temperatures, the fuel-bound nitrogen will form N_2 rather than NO_X. The fuel specification for these turbines, natural gas, has inherently low elemental nitrogen, so the effects of fuel NO_X are insignificant in comparison to thermal NO_x.

Prompt NO_X occurs primarily in combustion sources that use fuel rich combustion techniques. The formation of prompt NO_X occurs through several early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. The reactions primarily take place within fuel rich flame zones and are usually negligible when compared to the formation of NO_X by the thermal NO_X process. Combustion turbines generally have high mixing efficiencies with excess air, rich combustion zones rarely exist, and the formation of prompt NO_X is not deemed a significant contributing factor towards NO_X formation.

Since the formation of NO_X is largely dependent on thermal NO_X, several control technologies employ techniques to reduce the precursors of NO_X formation or use catalysts to treat the post combustion emissions. There are three types of emission controls for natural gas-fired turbines. The least effective are wet controls, which use steam or water injected into the combustion zone to reduce the ambient flame temperature, thus controlling NO_X formation. Intermediate are dry controls that use advanced combustor design to suppress NO_X formation. Most effective are post-combustion catalytic controls that selectively or non-selectively reduce NO_X. This project proposes the use of Dry-Low NO_X (DLN) combustion with SCR, so the less effective controls will not be analyzed.

SCONOX™

SCONOX™, is an emerging catalytic and absorption technology that has shown some promise for turbine applications. Unlike SCR, which requires ammonia injection, this system does not require ammonia as a reagent, and involves parallel catalyst beds that are alternately taken off line through means of mechanical dampers for regeneration.

SCONOX^{TM} works by simultaneously oxidizing CO to CO_2, NO to NO_2 and then absorbing NO_2. The NO_2 is absorbed into a potassium carbonate catalyst coating as KNO_2 and KNO_3. When a catalyst module begins to become loaded with potassium nitrites and nitrates, it is taken off line and isolated from the flue gas stream with mechanical dampers for regeneration. Once the module has been isolated from the turbine exhaust, four percent hydrogen in an inert gas of nitrogen or steam is introduced. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. Hydrogen reacts with potassium nitrites and nitrates during regeneration to form H_2O and N_2 that is emitted from the stack.

A typical arrangement has ten or fifteen sections of catalyst, although the number can vary on each system depending on size and other special design requirements. At any given time 80 percent of these sections are in the oxidation/absorption cycle and 20 percent are in the regeneration cycle.

Ideally suited to both new and retrofit applications, the SCONOX^{TM} system can operate effectively at temperatures ranging from 300 to 700 °F and does not limit gas turbine performance. A SCONOX^{TM} unit can be installed at the back-end of the boiler or in the heat recovery steam generator within the same envelope reserved for a SCR system.

Catalytic (Flameless) Combustion (XONON^{TM})

While several companies are reported to be working on this technology, it was first introduced commercially by Catalytica, Inc., and is being marketed under the name XONON^{TM}. The XONON^{TM} technology replaces traditional flame combustion with flameless catalytic combustion. NO_X control is accomplished through the combustion process using a catalyst to limit the temperature in the combustor below the temperature where NO_X is formed. The XONON^{TM} combustion system consists of four sections: 1) the preburner, for start-up, acceleration of the turbine engine, and adjusting catalyst inlet temperature if needed; 2) the fuel injection and fuel-air mixing system, which achieves a uniform fuel-air mixture to the catalyst; 3) the flameless catalyst module, where a portion of the fuel is combusted flamelessly; and 4) the burnout zone, where the remainder of the fuel is combusted.

Selective Catalytic Reduction (SCR)

SCR systems selectively reduce NO_X by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_X, ammonia, and oxygen react on the surface to form molecular nitrogen (N_2) and water. The catalyst, comprised of parallel plates or honeycomb structures, is installed in the form of rectangular modules, downstream of the gas turbine in simple-cycle configurations, and into the HRSG portion of the gas turbine downstream of the superheater in combined-cycle and cogeneration configurations.

The turbine exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the selective catalytic reduction system to operate properly. The temperature range is dictated by the catalyst, which is typically made from noble metals, base metal oxides, or zeolite-based material. The typical temperature range for base-metal catalysts is 450 to 800 °F. Keeping the exhaust gas temperature within this range is important. If it drops below 600 °F, the reaction efficiency becomes too low and increased amounts of NO_X and ammonia will be released out the stack. If the reaction temperature becomes too high, the catalyst may begin to decompose. Turbine exhaust gas is generally in excess of 1,000 °F. The HRSG cools the exhaust gases before they reach the catalyst by extracting energy from the hot turbine exhaust gases and creating steam for use in other industrial processes or to turn a steam turbine. In simple-cycle power plants where no heat recovery is accomplished, high temperature catalysts (e.g., zeolite) which can operate at temperatures up to 1,100 °F, are an option. Selective catalytic reduction can typically achieve NO_X emission reductions in the range of about 80 to 95 percent.

SCR uses ammonia as a reducing agent in controlling NO_X emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted from the stack is called ammonia slip. The ammonia is injected into the exhaust gases prior to passage through the catalyst bed.

Lean-Premix Technology

Turbine manufacturers have developed processes that use air as a diluent to reduce combustion flame temperatures, and have achieved reduced NO_X by premixing the fuel and air before they enter the combustor. This type of process is called lean-premix combustion, and goes by a variety of names, including the Dry-Low NO_X (DLN) process of General Electric, the Dry-Low Emissions (DLE) process of Rolls-Royce and the $SoLoNO_X$ process of Solar Turbines.

The burner, or combustor, is the space inside the gas turbine where fuel and compressed air are burned. The combustion chamber can take the shape of a long can, an axially-centered ring of long cans (can-annular combustor), an annulus located behind the compressor and in front of the gas turbine (annular combustor), or a vertical silo.

Conventional combustors are diffusion controlled. This means fuel and air are injected into the combustor separately and mix in small, localized zones. The zones burn hot and produce more NO_X. In contrast, lean-premix combustors minimize combustion temperatures by providing a lean-premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The lower temperatures reduce NO_X formation. However, because the mix is so lean, the flame must be stabilized with a pilot flame. Lean-premix combustors can achieve emissions of about 9 ppmvd NO_X at 15 percent oxygen (approximately 94 percent control).

To achieve low NO_X emission levels, the mixture of fuel and air introduced into the combustor (e.g., air/fuel ratio) must be maintained near the lean flammability limit of the mixture. Lean-premix combustors are designed to maintain this air/fuel ratio at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emission that occur as the air/fuel ratio reaches the lean flammability limit, lean-premix combustors switch to diffusion combustion mode at reduced load conditions. This switch to diffusion mode means that the NO_X emissions in this mode are essentially uncontrolled.

Steam/Water Injection

Higher combustion temperatures result in greater thermodynamic efficiency. In turn, more work is generated by the gas turbine at a lower cost. However, the more the gas turbine inlet temperature increases, the more NO_X that is produced. Diluent injection, or wet controls, can be used to reduce NO_X emissions from gas turbines. Diluent injection involves the injection of a small amount of water or steam via a nozzle into the immediate vicinity of the combustor burner flame. NO_X emissions are reduced by instantaneous cooling of combustion temperatures from the injection of water or steam into the combustion zone. The effect of the water or steam injection is to increase the thermal mass by mass dilution and thereby reduce the peak flame temperature in the NO_X forming regions of the combustor. Water injection typically results in a NO_X reduction efficiency of about 70 percent, with emissions below 42 ppmvd NO_X at 15 percent oxygen. Steam injection has generally been more successful in reducing NO_X emissions and can achieve emissions of less than 25 ppmvd NO_X at 15 percent oxygen (approximately 82 percent control).

Combustor geometry, injection nozzle design, and the fuel nitrogen content can affect diluent injection performance. Water or steam must be injected into the combustor so that a homogeneous mixture is created. Nonuniform mixing of water and fuel creates localized “hot spots” in the combustor that generate NO_X emissions. Increased NO_X emissions require more diluent injection to meet a specified level of emission. When diluent injection is increased, dynamic pressure oscillations in the combustor increase. Dynamic pressure oscillations can create noise and increase the wear and tear and required maintenance on the equipment. Continued increase of diluent injection will eventually lead to combustor flame instability and emission increases of CO and unburned hydrocarbons due to incomplete combustion.

Water is a better heat sink than steam; therefore more steam is required to reach a particular level of NO_X emission. However, newer gas turbines usually apply steam injection. Steam injection is generally a better alternative since it does not increase the heat rate as much as water, carbon monoxide emissions are increased a smaller amount, pressure oscillations are less severe, and maintenance is reduced.

Selective Non-Catalytic Reduction (SNCR), Thermal DeNO$_X$™

SNCR is based on the principle that ammonia or urea reacts with NO_X in the flue gas to form N_2 and H_2O. In practice, the technology has been applied in boilers by injecting ammonia into the high temperature (e.g., 1,300 ºF to 2,000 ºF) region of the exhaust stream. Incorrect location of injection points, insufficient residence times and miscalibration of injection rates may result in excess emissions of ammonia (ammonia slip), a toxic air pollutant. When successfully applied SNCR has shown reduction in NO_x emissions from boilers of 35 to 60 percent.

Thermal DeNO$_X$ is a high temperature selective non-catalytic reduction (SNCR) of NO_X using ammonia as the reducing agent. Thermal DeNO$_X$ requires the exhaust temperature to be above 1,800 ºF.

b) Technical Feasibility of The Control Techniques

SCONOX™

ABB Alston Power, as of December 1999, offered SCONOX™, with performance guarantees, to all owners and operators of natural gas-fired combustion turbines, regardless of size or gas turbine supplier. The system is designed to reduce both CO and NO_X emissions from natural gas-fired power plants to levels below ambient concentrations. CO emissions of 1 ppm and NO_X emissions of 2 ppm are guaranteed by the manufacturer. In addition, the regional administrator of EPA Region I, in a letter dated December 20, 1999, stated that the Region now considers SCONOX™ a technically feasible and commercially available air pollution control technology that is expected to obtain emission levels for criteria pollutants such as NO_X, CO and VOC comparable or superior to previously-applied technologies for large combined cycle turbine applications.

SCONOX™ has been demonstrated successfully on smaller power plants, including a 32 MW combined-cycle General Electric LM2500 gas turbine at the Federal Cogeneration facility, in Los Angeles, California. This facility uses water injection in conjunction with SCONOX™ to achieve a NO_X emissions rate of 0.75 ppm on a 15-minute rolling average. The SCONOX™ technology has also been successfully demonstrated on a 5 MW Solar Turbine Model Taurus 50 at the Genetics Institute in Andover, Massachusetts. The system is reducing NO_X down to 0.5 ppm NO_X, on a one-hour rolling average. The permit for the power plant was originally issued for 2.5 ppm NO_X.

In addition, US Generating was granted a construction permit on May 29, 1999, to use SCONOX™ for one of the 262 MW power islands at its 1,048 MW La Paloma plant near Bakersfield, California. The permit limits emissions to 2.0 ppmvd NO_X (at 15% O_2) on a three-hour average; a target of 1.0 ppmvd NO_X (at 15% O_2) on a 24-hour average.

PG&E Generating has filed an air permit application to use SCONOX^{TM} on its new 510 MW Otay Mesa power plant in San Diego County, California. PG&E's permit application seeks an initial NO_X limit of 2.0 ppm and a target rate of 1.0 ppm. Finally, Sunlaw Cogenerating Partners has filed an application to use SCONOX^{TM} on its 800 MW combined cycle plant in California.

XONON^{TM}

There is currently one field installation of the XONON^{TM} technology at a municipal power company, Silicon Valley Power, in Santa Clara, California, being used to perform engineering studies of the technology. NO_X emissions are well below 2.5 ppm on the 1.5 MW Kawasaki M1A-13A gas turbine. Catalytica Combustion Systems (manufacturer of XONON^{TM}) has a collaborative commercialization agreement with General Electric Power Systems, committing to the development of XONON^{TM}. In conjunction with General Electric Power systems, the XONON^{TM} system has been specified to be used with the GE 7FA turbines to be used at the proposed 750 MW natural gas-fired Pastoria Energy Facility, near Bakersfield, California. The project is expected to begin construction in 2001 and enter commercial operations by the summer of 2003. However, because the NO_X emissions limitations of 2.5 ppm have not been demonstrated in practice by a commercial facility, this technology is not considered commercially available at this time.

Selective Catalytic Reduction (SCR)

SCR is the most widely applied post-combustion control technology in turbine applications, and is currently accepted as LAER for new facilities located in ozone non-attainment regions. When combining with Dry-Low NO_X combustor, it can reduce NO_X emissions to as low as 2.5 ppmvd for standard combustion turbines without duct burner firing. Addition of the duct burners increases the emissions to approximately 3.5-9 ppmvd at 15% oxygen.

As mentioned previously, the side effect of this NO_X control system is ammonia slip. Ammonia slip occurs because the exhaust temperature falls outside the optimum catalyst reaction range or because the catalyst itself becomes prematurely fouled or exceeds its life expectancy. Some ammonia slip will occur regardless of the efficiency of the unit due to the SCR manufacturer's recommendation to inject NH_3 in amounts slightly above what is stoichiometrically required. Gas turbines using SCR typically have been limited to 10 ppmvd ammonia slip at 15 percent oxygen.

Lean-Premix Technology

Lean-premix technology is the most widely applied pre-combustion control technology in natural gas turbine applications. It has been demonstrated to achieve emissions of about 9 ppmvd NO_X at 15 percent oxygen (approximately 94 percent control).

Steam/Water Injection

Water injection typically results in a NO_X reduction efficiency of about 70 percent, with emissions below 42 ppmvd NO_X at 15 percent oxygen. Steam injection has generally been more successful in reducing NO_x emissions and can achieve emissions less than 25 ppmvd NO_X at 15 percent oxygen (approximately 82 percent control).

Selective Non-Catalytic Reduction (SNCR), Thermal DeNO$_X$^{TM}

The only known commercial applications of Thermal DeNO$_X$^{TM} are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800 ºF. There are no known applications on or experience with combustion turbines. Temperatures of 1,800 ºF require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased. This option has not been demonstrated on CTs. Thus, this control technology is not considered technically feasible and will be precluded from further consideration in this BACT analysis.

c) Control Technology Effectiveness and Impacts

SCONOX^{TM} provides the highest level of NO_X reduction and there are no significant environmental impacts from SCONOX^{TM} applications. However, SCONOX^{TM} is a very new technology and has yet to be demonstrated for long-term commercial operation on large scale combined cycle plants. The catalyst is subject to the same fouling or masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. This has led to reported outages in some cases due to catalyst fouling in the early stages of operations. Long-term performance is even more questionable, since adequate data is unavailable to determine the 'aging effect,' or degradation, in emission control performance over the long term. While this effect is also experienced with conventional SCR catalysts, operating experience with SCRs exists to better predict catalyst life and catalyst replacement cost is far less. Additionally, there are many operational unknowns since available technology would require a significant scale up to accommodate a facility of this size. Due to the extremely high cost per emission reduction of this control technology (over $26,000 per ton), it is ruled out as a control option for the Stephens Energy facility.

The next most effective control technology for NO_X is SCR, which is proposed by the applicant to satisfy BACT requirements, and which Air Quality determines meets or exceeds BACT. Thus, use of SCR with DLN combustors is selected such that the following limitations are met:

NO_X:	3.5 ppmvd @ 15% O_2 (24-hour average)
Ammonia slip:	10 ppmvd @ 15% O_2 (hourly average)

2. Auxiliary Boiler

The boiler design will incorporate low-NO_X burners for NO_X control, which is common for auxiliary boilers. The estimated NO_X emissions rate is 0.05 lb/MMBTU (LHV). No other more stringent control techniques were identified as available for this emissions unit. In addition, no adverse environmental or economic impacts are associated with this NO_X control technology. DEQ agrees that low-NO_X burners for NO_X control from the auxiliary boiler are acceptable as BACT.

3. Backup Diesel Generator And Diesel Fire Water Pump

Uncontrolled NO_X emissions of 2.16 lb/MMBTU (LHV) for the backup diesel generator and 4.41 lb/MMBTU (LHV) for the diesel fire water pump are based on manufacturer's data and engine design and are proposed as BACT. A review of the RBLC indicates that this type of equipment has not been required to install additional NO_X controls because of intermittent operation. The proposed BACT has no adverse environmental or energy impacts. DEQ agrees that engine design and a limitation on hours of operation is acceptable as BACT.

CO BACT Review

1. Combustion Turbines and Duct Burners

Carbon monoxide is formed as a result of incomplete combustion of fuel. 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 also tend to result in high NO_X emissions. Conversely, a low NOx emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO 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.

CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Alternative CO control methods include exhaust gas cleanup methods such as catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the combustors.

a) Identification of Control Techniques

A review of EPA's RACT/BACT/LAER Clearinghouse indicates several levels of CO control, which may be achieved for natural gas fired gas turbines. Emission levels and control technologies have been identified and ranked as follows:

- 2 to 6 ppm: CO oxidation catalyst (natural gas);
- 10 to 25 ppm: Combustion control for natural gas firing; oxidation catalyst for distillate oil firing; and
- 25 to 50 ppm: Combustion controls for distillate oil firing.

These levels of control are evaluated in terms of best available control technology in the following sections.

The most stringent CO control level available for the gas turbines would be achieved with the use of an oxidation catalyst system, which can remove approximately 80 percent of CO. According to the list of turbines in the RACT/BACT/LAER Clearinghouse with limits on CO, oxidation catalyst systems have been concluded to represent BACT for CO control for 11 of 117 turbines. The lowest emission level listed in the Clearinghouse is 3.0 ppm for the Wandotte Energy Facility in Michigan. A CO oxidation catalyst is concluded to represent the top control technology for CO for natural gas fired, combined-cycle turbines.

b) Technical Feasibility of The Control Techniques

Catalytic Oxidation

As 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 of CO to CO_2 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. 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}.

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 HRSG for proper turbine exhaust lateral distribution (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions. Operation with duct burners, at part load, or during start-up/shutdown will result in less than optimum temperatures and reduced control efficiency.

Typical pressure losses across an oxidation catalyst reactor (including pressure loss due to ammonium salt formation) are in the range of 1.5 to 3.0 inches of water (Engelhard 1999). Pressure losses in this range correspond roughly to a 0.15 to 0.30 percent loss in power output and fuel efficiency (General Electric 1997).

Catalyst systems are subject to loss of activity over time. 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. The following economic analysis assumes that catalyst will be replaced every 3 years per vendor guarantee. This system also would be expected to control a small percent (5-40%) of hydrocarbon (VOC) emissions.

c) Control Technology Effectiveness and Impacts

A CO catalyst also will oxidize other species within the turbine 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 $PM_{2.5}$. 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.

Capital and annual costs associated with installation of an oxidation catalyst system were calculated using vendor quotes. The basic equipment cost plus auxillaries for a GE 7FA unit was determined to be $1,087,000. Capital costs include the catalytic reactor, initial catalyst charge, freight, engineering and design, and installation. The purchased equipment cost is $1,299,000.

When adding direct installation costs and indirect costs, the total capital cost of this equipment is estimated at $2,150,700. Since the catalyst is assumed to be replaced periodically (every three years), it was deducted from the initial purchase cost in determining annualized capital recovery. Catalyst replacement is treated separately in this analysis under operating costs.

Annual operating costs include operating labor (1.0 hour/shift), routine inspection and maintenance, spent catalyst replacement, and lost cycle efficiency due to increased back pressure. Annualized catalyst replacement cost was calculated based on a 3 year life, for an annualized cost of about $361,700. Estimated annual costs total $992,100. At an estimated control efficiency of 80% to reduce CO, the use of an oxidation catalyst represents a maximum of 288.6 tons of CO removed per year for each gas turbine at a cost of $3,440 per ton of CO controlled.

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 NOx (an acid rain pollutant, a precursor to the formation of regional haze, and a precursor to the formation of ozone) is appropriately 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.

d) Summary

The use of an oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10} (and $PM_{2.5}$) emissions and is not cost effective. A review of EPA’s RBLC database indicates that other combustion turbines that utilize natural gas have been issued permits with BACT-based CO emissions in the range of 3 to 60 ppm (based on full load operation). Given the regional air quality conditions and the fact that the predicted maximum impact of CO emissions on the surrounding environment will not be significant, the proposed emission limits are believed to be representative of a top level of emission control. The best level of control for the combustion turbine generators is 10 ppmvd @ 15% O_2 without the duct burners firing and 16 ppmvd @ 15% O_2 with the duct burners firing (averaged on a 24-hour basis). Using combustion control has been determined to represent BACT for this facility. The resulting emission level results in modeled impacts which are less than the 1-hour and 8-hour CO NAAQS. There are no adverse economic, environmental or energy impacts associated with the proposed control alternative.

2. Auxiliary Boiler

The control technologies evaluated for use on the natural gas-fired auxiliary boiler include catalytic oxidation and proper boiler design/good operating practices. The cost of add-on controls on this unit is prohibitive. However, controlling boiler-operating conditions can minimize carbon monoxide emissions. This includes proper burner settings, maintenance of burner parts, and sufficient air, residence time, and mixing, for complete combustion. The maximum estimated CO emission rate is 0.085 lb/MMBTU (LHV). Thus, boiler design and good operating practices are proposed as BACT for controlling the CO emissions from the auxiliary boiler.

3. Backup Diesel Generator And Diesel Fire Water Pump

The control technologies for CO emissions evaluated for use on the backup diesel generator and the diesel-powered fire water pump are catalytic oxidation and proper design to minimize emissions. Because of the intermittent operation and low emissions, add-on controls would be prohibitively expensive. Thus, engine design is acceptable as BACT for controlling the CO emissions from the backup diesel generator and the diesel-powered fire water pump. Good combustion practices are have been determined as BACT resulting in CO emissions of 2.66 lb/MMBTU (LHV) for the backup diesel generator and 0.95 lb/MMBTU (LHV) for the diesel-powered fire water pump. The proposed BACT will not have any adverse environmental or energy impacts.

VOC BACT Review

1. Combustion Turbines and Duct Burners

The most stringent VOC control level for gas turbines has been achieved through advanced low NO_X combustors or catalytic oxidation which is also used for CO control. According to the list of turbines in the RACT/BACT/LAER Clearinghouse with limits on VOC, oxidation catalyst systems represent BACT for VOC control in only 2 of the facilities listed. An oxidation catalyst designed to control CO would provide a side benefit of controlling, in the range of 10 to 44 percent, VOC emissions. The next level of control is combustion controls where VOC emissions are minimized by optimizing fuel mixing, excess air, and combustion temperature to assure complete combustion of the fuel.

The same technical factors that apply to the use of oxidation catalyst technology for control of CO emissions (narrow operating temperature range, loss of catalyst activity over time, and system pressure losses) apply to the use of this technology for collateral control of VOC. Since the Stephens Energy Facility will not employ a CO catalyst, such collateral reductions in VOC are not available.

Since an oxidation catalyst has been shown to not be cost effective for control of 289 tons/yr/turbine of CO, it could not be cost effective for control of, at most 44 percent (BACT level of control), or 38 TPY of VOC per turbine. An oxidation catalyst cannot, therefore, be considered to represent BACT for VOC emissions from the Stephens Energy Facility. Therefore, good combustion practices and DLN technology have been determined to represent BACT for VOC controls for the gas turbines at the Stephens Energy Facility.

2. Auxiliary Boiler

The control technologies evaluated for use on the natural gas-fired auxiliary boiler include catalytic oxidation and proper boiler design and good combustion practices. The cost of add-on controls on this unit is prohibitive. However, optimizing boiler-operating conditions will minimize VOC emissions. The maximum estimated VOC emission rate is 0.016 lbs/MMBTU (LHV). Thus, boiler design and good operating practices have been determined as BACT for controlling VOC emissions from the auxiliary boilers. The proposed BACT will not have any adverse environmental or energy impacts.

3. Backup Diesel Generator And Diesel Fire Water Pump

A review of the RBLC indicates that this type of equipment has not been required to install additional VOC controls because of intermittent operation. DEQ agrees that engine design is acceptable as BACT.

<u>SO_2 BACT Review</u>

1. Combustion Turbines and Duct Burners

Control techniques available to reduce SO_2 emissions include flue gas desulfurization (FGD) systems and the use of low sulfur fuels. A review of the RLBC indicates that while FGD systems are common on boiler applications, there are no known FGD systems on combustion turbines. Thus, the use of an FGD system is not warranted and an FGD system is rejected as a BACT control alternative.

The proposed Stephens Energy Facility will utilize pipeline-quality natural gas in the turbines and duct burners. The maximum estimated SO_2 emissions would be 0.006 lb/MMBTU (LHV) for the turbines with duct burners. The use of very low sulfur fuel has an established record of compliance with applicable regulations. The NSPS establish maximum allowable SO_2 emissions associated with combustion turbines and require either an SO_2 emission limitation of 150 ppm or a maximum fuel content of 0.8 percent by weight (40 CFR Part 60, Subpart GG). The estimated emissions for these units are significantly less than the NSPS limit. Therefore, the very low SO_2 emission rate that results from the use of natural gas is proposed as BACT for the turbines and duct burners. There are no adverse environmental or energy impacts associated with the proposed control alternative.

2. Auxiliary Boiler

The control technologies evaluated for use on the natural gas-fired auxiliary boiler for SO_2 control include those listed previously for the turbines and duct burners. The cost of add-on controls on intermittently operated facilities is prohibitive. Thus, the use of natural gas is acceptable as BACT.

3. Backup Diesel Generator And Diesel Fire Water Pump

The only control technology available for diesel engines that operate less than 500 hours per year is use of low sulfur fuel. Therefore, the use of very low sulfur diesel fuel (0.05 weight % sulfur) represents BACT for the diesel engines.

PM_{10} BACT Review

1. Combustion Turbines and Duct Burners

Total suspended particulates (TSP) and particulate matter less than 10 micrometers will occur from the combustion of natural gas. The EPA's AP-42, Fifth Edition, Supplement D, Section 1, considers that particulate matter to be less than 1 micron, so all emissions are considered as PM_{10}. The PM_{10} emissions from the combustion of natural gas will result primarily from inert solids contained in the unburned fuel hydrocarbons, which agglomerate to form particles. PM_{10} emission rates from natural gas combustion are inherently low because of very high combustion efficiencies and the clean burning nature of natural gas. Therefore, their use is in and of itself a highly efficient method of controlling emissions. The maximum estimated PM_{10} emission rate is 0.015 lbs/MMBTU from the turbines with duct burner firing. Based on the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, there are no BACT precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbines. Therefore, BACT for PM_{10} emissions from the combustion turbines with duct burner firing is proposed to be the use of a low ash fuel and efficient combustion. This BACT choice will be protective of any reasonable opacity standard. Typically, plume visibility is not an issue for this type of facility as the exhaust plumes are nearly invisible except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the proposed control alternative.

2. Auxiliary Boiler

Since the auxiliary boiler will fire natural gas, the same properties that applied to the combustion turbines will also apply to this application. The maximum estimated TSP/PM_{10} emission rate is 0.01 lbs/MMBTU. The EPA's RACT/BACT/LAER Clearinghouse (RBLC) database research indicates that there are no BACT precedents for TSP/ PM_{10} requiring add-on controls. Therefore, BACT for TSP/PM_{10} is proposed to be the use of a low ash fuel and efficient combustion. Opacity is also not an issue with this type of application, except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the proposed control alternative.

3. Backup Diesel Generator And Diesel Fire Water Pump

These units, like the turbines and auxiliary boiler, emit particulates consisting of ash in the fuel and residual carbon and hydrocarbons caused from incomplete combustion. The applicant's review of RBLC shows that good combustion control and/or good engine design is the most stringent requirement for this application. An emission rate of 0.124 lbs/MMBTU (LHV) and 0.31 lbs/MMBTU (LHV) for the backup generator and the fire water pump, respectively, is proposed for BACT. The proposed BACT will not have any adverse environmental or energy impacts. DEQ has agreed that combustion control and good engine design are acceptable as BACT, without further analysis.

4. Cooling Towers

There are no technically feasible alternatives that can be installed on the cooling towers, which specifically reduce particulate emissions; however, cooling towers are typically designed with drift elimination features. The drift eliminators are specifically designed baffles that collect and remove condensed water droplets in the air stream. These drift eliminators, according to a review of the EPA's RBLC, can reduce drift to 0.001 percent to 0.004 percent of cooling water flow, which reduces particulate emissions. Therefore, the use of drift eliminators to attain an emission rate of 1.2 lb/hr is determined as BACT for cooling tower particulate emissions. The proposed BACT will not have any adverse environmental or energy impacts.

Summary of Selected BACT

Pollutant	Gas Turbine with Duct Burner (permit limit)	Auxiliary Boiler (permit limit)	Diesel Engine/Fire Water Pump (permit limit)
NO_X	SCR with dry low-NOx combustors (3.5 ppmvd @ 15% O_2 and 10 ppmvd ammonia slip)	low NO_X burner (1.65 lb/hr)	good engine design (10.2/6.2 lb/hr)
CO	good combustion control (10 ppmvd @ 15% O_2)	good combustion practice (2.8 lb/hr)	good engine design (12.6/1.3 lb/hr)
VOC	good combustion practice	boiler design and good operating practices	good engine design
SO_2	low sulfur fuel (natural gas, 14.5 lb/hr)	low sulfur fuel (natural gas, 0.2 lb/hr)	0.05% sulfur diesel (0.3/0.4 lb/hr)
PM_{10}	good combustion control, use of natural gas (34.5 lb/hr)	good combustion practice (0.33 lb/hr)	good engine design, (20% opacity)

Start-up and Shutdown

The turbines will undergo periods of start-up and shutdown in response to power demands. Start-up is defined as the period between the first fire of a turbine through the period when the turbine operation reaches Mode 6. This period will last for no more than four hours for each event. Shutdown is defined as the period between the initiation of shutdown operations as defined by the vendor's sequence of shutdown operations and the cessation of firing in the turbine.

Excess emissions during start-up and shutdown are caused by technological limitations of the General Electric Dry Low NO_X (DLN) burners used to control NO_X emissions from the turbines. By design the DLN system must cycle through four distinct stages to safely bring the burner on line in its final low NO_X configuration. The computer controlled process is fine-tuned to minimize the amount of NO_X formation during steady state operation, but it is inherently unstable during start-up and shutdown. During these unstable conditions, the mixture of air and gas is adjusted to increase the fuel to air ratio to maintain combustion and prevent flameout. This richer than normal mixture results in elevated levels of NO_X due to higher flame temperatures. As a result, excess emissions will occur during start-ups and shutdowns of the combustion turbines.

In accordance with OAC 252:100-9-3.3(b), excess emissions that result from start-up and shutdown emissions are exempt from compliance with air emission limitations established in the permits, rules, and orders of the DEQ under specific conditions. This exemption is based on the Duke Energy Stephens facility compliance with the requirements of OAC 252:100-9-3.1 and OAC 252:100-9-3.3(c) and the demonstration required in OAC 252-100-9-3.3(b).

B. Air Quality Impacts

Prevention of Significant Deterioration (PSD) is a construction permitting program designed to ensure air quality does not degrade beyond the National Ambient Air Quality Standards (NAAQS) or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then they trigger this review process. EPA has provided modeling significance levels for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. Air quality impact analyses were conducted to determine if ambient impacts would be above the EPA defined modeling and monitoring significance levels. If impacts are above the modeling significance levels, a radius of impact is defined for the facility for each pollutant out to the farthest receptor at or above the significance levels. If a radius of impact is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required for the Class II area.

Modeling conducted by the applicant and reviewed by the DEQ demonstrated that emissions from the facility will not exceed the PSD modeling significance levels for NO_2, PM_{10}, SO_2, and CO. A full impact analysis was not required for the listed criteria pollutants.

VOC is not limited directly by NAAQS. Rather, it is regulated as an ozone precursor. EPA developed a method for predicting ozone concentrations based on VOC and NO_X concentrations in an area. The ambient impacts analysis utilized these tables from "VOC/NO_X Point Source Screening Tables" (Richard Scheffe, OAQPS, September, 1988). The Scheffe tables utilize increases in NO_X and VOC emissions to predict increases in ozone concentrations.

<u>Modeling Methodology</u>

The dispersion modeling for the Stephens Energy Facility was conducted in two phases. First, a screening analysis was performed to determine the ambient condition and combustion turbine operating load that would result in the highest predicted impact for each pollutant and averaging period. Twenty-two turbine load and temperature scenarios were evaluated. Screening analyses were also conducted to evaluate impacts from the auxiliary boiler, back-up diesel generator, and fire water pump. As noted above, emissions during start-up and shutdown were not included in the modeling analyses, because the facility is exempt from these limits due to a technological limitation on unit operation. Maximum impacts from these worst case scenarios were then compared to the significant impact levels (SIL). If impacts were below the SIL, the screening results were used to determine that there was no significant impact from the facility and no further modeling of the applicable criteria pollutants was conducted.

If, however, the screening results indicated impacts above the SIL, refined modeling was used to obtain a more accurate (less conservative) impact analysis. The maximum turbine impact scenario was used along with the other sources (i.e. auxiliary boiler, back-up diesel generator, fire water pump, cooling tower, and inlet air chiller units).

The screening analysis was conducted using SCREEN3. The refined air quality modeling analyses employed USEPA's Industrial Source Complex (ISC3) (Version 00101) model (USEPA, 1995a). The ISC3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474). The regulatory default option was selected such that USEPA guideline requirements were met.

The stack height regulations promulgated by USEPA on July 8, 1985 (50 CFR 27892), established a stack height limitation to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. The regulations specify that Good Engineering Practice (GEP) stack height is the maximum creditable stack height which a source may use in establishing its applicable State Implementation Plan (SIP) emission limitation. For stacks uninfluenced by terrain features, the determination of a GEP stack height for a source is based on the following empirical equation:

$$H_g = H + 1.5L_b$$

where:

H_g = GEP stack height;

H = Height of the controlling structure on which the source is located, or nearby structure; and

L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. The area in which a nearby structure can have a significant influence on a source is limited to five times the lesser dimension (height or width) of that structure, or within 0.5 mile (0.8 km) of the source, whichever is less. The methods for determining GEP stack height for various building configurations have been described in USEPA's technical support document (USEPA, 1985).

Since the heights of exhaust stacks at the proposed power plant are less than respective GEP stack heights, a dispersion model to account for aerodynamic plume downwash was necessary in performing the air quality impact analyses.

Since downwash is a function of projected building width and height, it is necessary to account for the changes in building projection as they relate to changes in wind direction. Once these projected dimensions are determined, they can be used as input to the ISC3 model.

In October 1993, USEPA released the Building Profile Input Program (BPIP) to determine wind direction-dependent building dimensions. The BPIP algorithms as described in the User's Guide (USEPA, 1993), have been incorporated into the commercially available BREEZEWAKE program. The BREEZEWAKE program was used to determine the wind direction-dependent building dimensions for input to the ISC3 model.

The BPIP program builds a mathematical representation of each building to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10 degree intervals). If the BPIP program determines that a source is under the influence of several potential building wakes, the structure or combination of structures which has the greatest influence ($H + 1.5\ L_b$) is selected for input to the ISCST3 model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is 5 L_b downwind, 2 L_b upwind, and 0.5 L_b crosswind. These criteria are based on recommendations by USEPA. The input to the BREEZEWAKE preprocessing program consisted of proposed power plant exhaust stacks (two CTs and an auxiliary boiler) and building dimensions.

Due to the relatively high stack heights and the relatively small size of the dominant structures, the building cavity effects that were considered in the modeling analysis were minimal. For this analysis, the first step was to determine the building cavity height based on the formula:

$$h_c = H + 0.5L_b$$

where:

h_c = GEP stack height;

H = Height of the controlling structure on which the source is located, or nearby structure; and

L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

If the stack height was greater than or equal to the cavity height, the cavity effect would not affect the downwind maximum impacts. However, if a cavity effect was possible, the length of the cavity was compared to the distance to the nearest receptor.

Due to the size of the property, the location of the sources on the property, the height of the stacks, and the distance of the sources from the fence line, no cavity effects were encountered at any receptors. Therefore, the concentrations at all receptors were estimated using the normal procedures in the ISCST3 model.

The meteorological data used in the dispersion modeling analyses consisted of six years (1984-1991 excluding 1988 and 1989) of hourly surface observations from the Oklahoma City, Oklahoma, National Weather Service Station and coincident mixing heights from Oklahoma City (1986-1988) and Norman, Oklahoma (1990 and 1991). These six years were chosen to encompass the five years that have been included in the CALPUFF analysis.

Surface observations consist of hourly measurements of wind direction, wind speed, temperature, and estimates of ceiling height and cloud cover. The upper air station provides a daily morning and afternoon mixing height value as determined from the twice-daily radiosonde measurements. Based on NWS records, the anemometer height at the Oklahoma City station during this period was 7.01 meters.

Prior to use in the modeling analysis, the meteorological data sets were scanned for missing data. The procedures outlined in the USEPA document, "Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models," were used to fill gaps of information for single missing days. For larger periods of two or more missing days, seasonal averages were used to fill in the missing periods. The USEPA developed rural and urban interpolation methods to account for the effects of the surrounding area on development of the mixing layer boundary. The rural scheme was used to determine hourly mixing heights representative of the area in the vicinity of the proposed power plant.

The urban/rural classification is used to determine which dispersion parameter to use in the model. Determination of the applicability of urban or rural dispersion is based upon land use or population density. For the land use method the source is circumscribed by a three kilometer radius circle, and uses within that radius analyzed to determine whether heavy and light industrial, commercial, and common and compact residential, comprise greater than 50 percent of the defined area. If so, then urban dispersion coefficients should be used. The land use in the area of the proposed facility is not comprised of greater than 50 percent of the above land use types.

For the population density method, the area is reviewed to determine the average population density in people per square kilometer. If the resulting value is greater than 750 people/km^2 or 21,200 people, the area is considered urban. The population density per the 1990 census for the location of the proposed permit does not meet this criterion.

The refined modeling used a nested Cartesian grid. Receptors were placed no greater than 25 meters apart along the boundary. From the fenceline, a 25-meter grid of receptors extended out to 500 meters. A 100-meter grid extended beyond this grid, out to 1 kilometer form the site. Beyond that, a spacing of 500 meters was used extending 5 kilometers from the facility. The screening analysis was used to locate the maximum impact areas. All receptors were modeled with actual terrain based on the proposed plant location. The terrain data was taken from United States Geologic Society (USGS) standard 7.5-minute topographic maps. All building, source location, and terrain data were based on the NAD27 datum.

Stack Parameters and Emission Rates

The stack emission rates and parameters needed for the proposed power plant included each of the two exhaust stacks of the two CTs, the exhaust stack of the auxiliary boiler, and the cooling water towers. The cooling water towers contribute a minimal amount of particulate matter emissions. The proposed CTs can operate at various loads. The emission rates used for the analysis were the maximum estimated emission rates for each pollutant at maximum load.

Stack Parameters							
Source	**Easting**	**Northing**	**Elevation**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	M	**M**	**M**	**M**	**K**	**M/s**	**M**
Turbine No.1	595640	3810102	319.1	49.073	366.5	21.15	5.486
Turbine No.2	595598	3810102	319.1	49.073	366.5	21.15	5.486
Aux. Boiler	595698	3810094	319.1	18.288	476.5	12.19	0.813
Emerg. Gen.	595668	3810096	319.1	6.096	914.8	66.20	0.203
FW Pump	595647	3810190	319.1	4.267	804.3	24.63	0.152
CW Tower 01	595739	3810136	319.1	14.33	293.2	14.33	12.477
CW Tower 02	595739	3810121	319.1	14.33	293.2	14.33	12.477
CW Tower 03	595739	3810106	319.1	14.33	293.2	14.33	12.477
CW Tower 04	595739	3810090	319.1	14.33	293.2	14.33	12.477
CW Tower 05	595739	3810074	319.1	14.33	293.2	14.33	12.477
CW Tower 06	595739	3810058	319.1	14.33	293.2	14.33	12.477
CW Tower 07	595740	3810043	319.1	14.33	293.2	14.33	12.477
CW Tower 08	595740	3810027	319.1	14.33	293.2	14.33	12.477
CW Tower 09	595740	3810012	319.1	14.33	293.2	14.33	12.477
CW Tower 10	595740	3809996	319.1	14.33	293.2	14.33	12.477
CW Tower 11	595552	3810103	319.1	13.72	293.2	14.33	3.670
CW Tower 12	595557	3810103	319.1	13.72	293.2	14.33	3.670
CW Tower 13	595561	3810103	319.1	13.72	293.2	14.33	3.670
CW Tower 14	595565	3810103	319.1	13.72	293.2	14.33	3.670
CW Tower 15	595552	3810087	319.1	13.72	293.2	14.33	3.670
CW Tower 16	595556	3810087	319.1	13.72	293.2	14.33	3.670
CW Tower 17	595560	3810087	319.1	13.72	293.2	14.33	3.670
CW Tower 18	595564	3810087	319.1	13.72	293.2	14.33	3.670
CW Tower 19	595552	3810070	319.1	13.72	293.2	14.33	3.670
CW Tower 20	595556	3810070	319.1	13.72	293.2	14.33	3.670
CW Tower 21	595560	3810070	319.1	13.72	293.2	14.33	3.670

Stack Parameters (Cont.)							
Source	**Easting**	**Northing**	**Elevation**	**Stack Ht.**	**Stack Temp.**	**Stack Vel.**	**Stack Dia.**
	M	**M**	**M**	**M**	**K**	**M/s**	**M**
CW Tower 22	595564	3810070	319.1	13.72	293.2	14.33	3.670
CW Tower 23	595552	3810053	319.1	13.72	293.2	14.33	3.670
CW Tower 24	595556	3810053	319.1	13.72	293.2	14.33	3.670
CW Tower 25	595560	3810053	319.1	13.72	293.2	14.33	3.670
CW Tower 26	595564	3810053	319.1	13.72	293.2	14.33	3.670

Emission Rates				
Source	**CO**	**SO_2**	**PM_{10}**	**NO_X**
	lb/hr	**lb/hr**	**lb/hr**	**lb/hr**
Turbine No.1(1)	88.1	14.5	34.5	32.0
Turbine No.2(1)	88.1	14.5	34.5	32.0
Aux. Boiler – 1 & 8 hr	4.946	---	---	---
Aux. Boiler – 3 & 24 hr	---	0.205	0.330	---
Aux Boiler – Annual	---	0.140	0.226	3.956
Backup Gen. – 1 & 8 hr	12.55	---	---	---
Backup Gen. – 3 & 24 hr(4)	---	0.269	0.591	---
Backup Gen. – Annual(5)	---	0.003	0.007	0.60
FW Pump – 1 & 8 hr	1.336	---	---	---
FW Pump – 3 & 24 hr(4)	---	0.410	0.440	---
FW Pump – Annual(5)	---	0.005	0.005	0.36
CW Tower (1-10)(3)	---	---	0.12	---
CW Cells (11-26)	---	---	0.02	---

(1) Includes the CTG and the duct burner.
(2) Auxiliary Boiler emissions are limited to 6,000 hours per year.
(3) Emissions are evenly spread across 10 cells (emissions points).
(4) 2 hr/day and /3 hr period
(5) 100 hours per year of planned operation

<u>Modeling Results</u>

The modeling results are shown below. The applicant has demonstrated compliance through the application of the NO_2/NO_X ratio of 0.75 as is allowed in the "Guideline on Air Quality Models." The highest first high concentrations over the five-year period were used to demonstrate compliance with the modeling significance levels for each pollutant.

The modeling indicates facility emissions will result in ambient concentrations below the significance levels in which an area of impact is defined. Therefore, no additional modeling for PSD increment or NAAQS compliance is required.

Significance Level Comparisons				
Pollutant	**Averaging Period**	**Year**	**Max. Concentrations ($\mu g/m^3$)**	**Significance Level ($\mu g/m^3$)**
NO_2	Annual	1990	0.64	1
CO	8-hour	Screen	264	500
	1-hour	Screen	979	2000
PM_{10}	Annual	1984	0.43	1
	24-hour	1984	3.50	5
SO_2	Annual	1990	0.09	1
	24-hour	1986	1.26	5
	3-hour	1991	20.77	25

An ozone analysis was carried out based on the method in "VOC/NO_X Point Source Screening Tables" created by Robert Scheffe from the results of reactive plume modeling of the emissions of volatile organic compounds (VOC) and NO_X. The impact of all proposed VOC and NO_X emissions associated with the project is estimated at 0.015 ppm. Based on a fourth high (design) monitored concentration for the years 1998, 1999 and 2000 of 0.085 ppm from the Lawton site (400310647-1), the projected emissions will not exceed the ozone NAAQS of 0.12 ppm.

C. Evaluation of PSD Increment Consumption

Based on the analysis in B above, increment consumption analysis is not required.

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

The facility does not have a significant impact in air quality, so a full NAAQS analysis is not required.

E. Ambient Monitoring

The predicted maximum ground-level concentrations of pollutants by air dispersion models have demonstrated that the ambient impacts of the facility are below the monitoring exemption levels for NO_2, CO, SO_2 and PM_{10}. Neither pre-construction nor post-construction ambient monitoring will be required for these pollutants. However, VOC emissions are greater than the 100 TPY monitoring significance level. Therefore, ozone pre-construction monitoring is required. The 1998 Lawton Monitoring Site (No. 400310647-1) located 38.6 km north and 20.9 km west of the facility will provide conservative monitoring data in lieu of pre-construction monitoring.

Comparison of Modeled Impacts to Monitoring Exemption Levels			
Pollutant	**Monitoring Exemption Levels**		**Ambient Impacts**
	Averaging Time	**μg/m^3**	**μg/m^3**
NO_2	Annual	14	0.64
CO	8-hour	575	264
PM_{10}	24-hour	10	3.50
SO_2	24-hour	13	1.26
VOC	100 TPY of VOC		174 TPY VOC

1998 Monitoring Data Summary	
Monitor 400310647-1	
Ranking	**Concentration (ppm)**
First High	0.092
Second High	0.088
Third High	0.085
Fourth High	0.085

F. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, Visibility

Mobile Sources

Current EPA policy is to require an emissions analysis to include mobile sources. In this case, mobile source emissions are expected to be negligible. Few employees will be needed. The fuel for the plant will arrive by pipeline rather than by vehicle.

Growth Impacts

The purpose of the growth impact analysis is to quantify the possible net growth of the population of the area as a direct result of the project. This growth can be measured by the increase in residents of the area, the additional use and need of commercial and industrial facilities to assist the additional population with everyday services, and other growth, such as additional sewage treatment discharges or motor vehicle emissions.

Approximately 300 trade jobs (i.e., welders, electricians, construction workers, etc.) over a 22 month period will be needed to complete the construction of the project. It is anticipated that the majority of these jobs will be local hires, thus not requiring any additional residential or commercial capacity within the area. Approximately 2 percent will be temporary out-of-town supervisors who will reside in local hotels for the extent of the construction. Approximately 25 full-time positions will be made available for local hiring after construction. There should be no substantial increase in community growth or the need for additional infrastructure. Therefore, it is not anticipated that the project will result in an increase in secondary emissions associated with non-project related activities or growth.

Ambient Air Quality Impact Analysis

The purpose of this aspect of impact analysis is to predict the air quality in the area of the project during construction and after commencing operation. This analysis follows the growth analysis by combining the associated growth with the emissions from the proposed project and the emissions from other permitted sources in the area to predict the estimated total ground-level concentrations of pollutants as a result of the project, including construction.

The only source of additional emissions may be from fugitive dust generated from equipment transportation or vehicles during construction. Any long-term air quality impact in the area will result from emissions increases due to operation of the facility. These impacts have been analyzed in preceding sections.

Soils and Vegetation Impact

The Soil Conservation Services (SCS) Soil Survey of Stephens County identifies the primary soil units on this site to be the Dennis-Bates-Coweta complex and the Taloka-Parsons-Stigler complex. The main crops typically grown on the soils identified within the area of interest are native grasses and tame pasture plants. In a few areas, Dennis and Bates soils are used for grain sorghum, small grains, and soybeans. No sensitive aspects of the soil and vegetation in this area have been identified. As such, the secondary National Ambient Air Quality Standards (NAAQS), which establish ambient concentration levels below which it is anticipated that no harmful effects to either soil or vegetation can be expected, are used as the benchmark for this analysis.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

SO_2 enters the plant primarily through the leaf stomata and passes into the intercellular spaces of the mesophyll, where it is absorbed on the moist cell walls and combined with water to form sulfurous acid and sulfite salts. Plant species show a considerable range of sensitivity to SO_2. This range is the result of complex interactions among microclimatic (temperature, humidity, light, etc.), edaphic, phenological, morphological, and genetic factors that influence plant response (USEPA, 1973).

NO_2 may affect vegetation either by direct contact of NO_2 with the leaf surface or by solution in water drops, becoming nitric acid. Acute and chronic threshold injury levels for NO_2 are much higher than those for SO_2 (USEPA, 1971).

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. The modeling conducted, which demonstrated compliance with the Primary NAAQS simultaneously demonstrated compliance with the Secondary NAAQS because the Secondary NAAQS are higher or equal to the Primary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated due to the proposed power plant.

Visibility Impairment

Visibility is affected primarily by PM and NO_X emissions. The area near the facility is primarily agricultural, consisting of pastureland. Some residences are located west of the site. The closest airport is located approximately four miles northwest of the facility. Therefore, there are no airports, scenic vistas, or other areas that would be affected by minor reductions in visibility. The project is not expected to produce any perceptible visibility impacts in the vicinity of the plant. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It is concluded that there will be minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation will result in 0% opacity, no local visibility impairment is anticipated.

G. Class I Area Impact Analysis

A further requirement of PSD includes the special protection of air quality and air quality related values (AQRV) at potentially affected nearby Class I areas. Assessment of the potential impact to visibility (regional haze analysis) is required if the source is located within 100 km of a Class I area. The Stephens Energy Facility is within 100 km of the nearest Class I area, which is the Wichita Mountains Natural Wildlife Refuge (WMNWR). Therefore, the proposed Stephens Energy Facility was evaluated for it's impacts on the WMNWR.

The impacts were evaluated in accordance with the Interagency Working Group on Air Quality Modeling (IWAQM) and USEPA guidelines for determining long-range impacts at nearby Class I areas. Potential impacts were modeled using CALPUFF in its screening mode. The model was used to evaluate impacts on PSD increment consumption and air quality related values such as visibility and deposition impacts.

The screening mode consists of the same meteorological data set as used for the ISCST3 modeling along with four additional hourly parameters. Three receptors sets consisting of concentric rings are used with radii equal to the distance between Stephens Energy Facility and 1) the closest WMNWR point; 2) the farthest point within the WMNWR; and 3) a point between the two extremes. Each ring consisted of 360 receptors placed 1° apart. Receptors within the innermost ring were assigned a terrain elevation equal to the elevation of the WMNWR at its closest point. Receptors within the outermost ring were assigned a terrain elevation equal to the elevation of the WMNWR at its farthest point. Receptors on the inner ring were assigned the elevations representative of the terrain within the center of the WMNWR.

Listed below are the maximum concentrations for the applicable pollutants and averaging periods along with the applicable PSD Class I increment levels. Since all of the impacts are significantly below the PSD Class I increment of 8 μg/m^3, so it is not necessary to evaluate cumulative PSD increment consumption.

Significance Level Comparisons				
Pollutant	**Averaging Period**	**Year**	**Max. Concentrations (μg/m^3)**	**PSD Class I Increment (μg/m^3)**
NO_2	Annual	1987	2.77 E-7	2.5
PM_{10}	Annual	1987	2.89 E-7	4.0
	24-hour	1987	1.06 E-4	8.0
SO_2	Annual	1987	1.12 E-7	0.1
	24-hour	1987	4.15 E-5	0.2
	3-hour	1987	3.29 E-4	1.0

Visibility Impacts

In keeping with IWAQM guidance, impacts to visibility were assessed using the CALPUFF model to estimate the maximum 24-hour average concentrations of primary and secondary particulates. The modeling system consists of diagnostic meteorological models, a Gaussian puff dispersion model with algorithms for chemical transformation, wet and dry deposition, and complex terrain, and a post processor (CALPOST) for calculating concentration and deposition field and visibility impacts. The modeling systems/techniques provide ground level concentrations of visibility pollutants. These concentrations can then be used to calculate the extinction due to these pollutants.

The modeled concentrations are multiplied by an extinction coefficient that estimates the effect on absorption and scattering of visible light and a relative humidity factor that simulates enlargement due to droplet formation. The total plume extinction is then compared to a background value to determine if the impact is significant. In making the comparison, it is inherently assumed that the modeled concentration is representative of a wide area surrounding the observer.

For the Stephens Energy Facility, incremental increases in NO_2 and PM_{10} were modeled using CALPUFF to determine concentrations of these pollutants at the WMNWR Class I area. Results of the CALPUFF modeling were then processed using CALPOST. Hourly relative humidity values were available in the meteorological data set for use in the modeling to determine the relative humidity adjustment factor f(RH) used in the postprocessor. In keeping with the guidance from the Federal Land Manager (FLM) Air Quality Related Values Workgroup (FLAG), the maximum hourly relative humidity values were set in the post-processing to 95 percent.

The natural background estimate for the visibility reference level for the WMNWR is 15.7 mm-1 (FLAG 1999). The maximum 24-hour change in extinction was predicted as 4.14 percent. Since the maximum impact is below 5 percent, visibility impacts are considered insignificant.

Deposition Impacts

At the request of Air Quality, an evaluation of deposition impacts at the WMNWR was performed using CALPUFF. The maximum annual impacts for HNO_3, NO_3, NO_X, SO_2, SO_4 were evaluated and used to determine their contributions to total deposition in kg/ha/yr. The maximum annual deposition for nitrogen and sulfur were calculated at 2.71 E-3 kg/ha/yr and 2.90 E-3 kg/ha/yr, respectively.

According to the FLAG final report (FLM 2000), the sensitivity of ecosystems to sulfate or nitrate deposition varies depending on the species of flora and fauna in the ecosystems, as well as the existing pH and buffering capacity of the soils or water bodies. Ongoing research to define a "critical load" beyond which deleterious effects may be expected cite loads as low as 2.7 kg/ha/yr of wet deposition of sulfur and as low as 10 kg/ha/yr for nitrogen. The U.S. Forest Service (USFS) presents a method for calculating the impact of sulfate and nitrate deposition on a lake; however, this method required data on the existing acidity, watershed area, and annual precipitation for a particular lake (USFS 2000). Without this data, a quantitative assessment of deposition impact on WMNWR cannot be performed. Nevertheless, given that the maximum deposition rates are at least three orders of magnitude below the cited FLAG Guidelines, it is expected that the deposition impacts from the Stephens Energy Facility on WMNWR will be negligible.

SECTION V. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-3 (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. In addition, modeled emissions from the proposed facility demonstrate that the facility would not have a significant impact on air quality.

OAC 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2000, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. NSPS regulations are addressed in the "Federal Regulations" section.

OAC 252:100-5 (Registration, Emission Inventory, And Annual Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. Since this is construction for a new facility, no emission inventories or fees have previously been paid.

OAC 252:100-7 (Permits for Minor Facilities) [Not Applicable]
Subchapter 7 sets forth the permit application fees and the basic substantive requirements for permits for minor facilities. The current project will be a major source that is subject to Subchapter 8 permitting.

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

5 TPY of any one criteria pollutant
2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule
0.6 TPY of any one Category A toxic substance
1.2 TPY of any one Category B toxic substance
6.0 TPY of any one Category C toxic substance

Emissions limitations have been established for each emission unit based on information from the permit application.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day following the malfunction or release. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Excess emissions during turbine start-up and shutdown are caused by technological limitations on unit operation. The facility will comply with paragraph 3.1(b)(2) of this subchapter, including an initial notification of this condition and then immediate notice and quarterly reporting thereafter. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

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]
Subchapter 19 regulates emissions of particulate matter from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Therefore, the units listed below are subject to the requirements of this subchapter and will be in compliance as shown in the following table.

Equipment	**Max. Heat Input (MMBTUH) (HHV)**	**Allowable PM Emission Rate (lb/MMBTU) (HHV)**	**Potential PM Emissions (lb/MMBTU) (HHV)**
Each Turbine	1,871	0.165	0.010
Each Duct Burner	622	0.225	0.025
Auxiliary Boiler	36	0.44	0.010
Backup Generator	<10	0.60	0.113
Diesel Fire Water Pump	<10	0.60	0.310

OAC 252:100-25 (Visible Emissions, and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The turbines and duct burners (electric utility steam generating units) are subject to opacity limits under NSPS, Subpart Da. Thus, they are exempt from the opacity limits of Subchapter 25. The other emissions units shown in the table above are subject to this subchapter. The auxiliary boiler will assure compliance with this regulation by ensuring "complete combustion" and utilizing pipeline-quality natural gas as fuel. The backup diesel generator and the diesel fire water pump will assure compliance with this regulation by ensuring "complete combustion."

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 originated 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 to interfere with the maintenance of air quality standards. No activities are expected that would produce fugitive dust beyond the facility property line.

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, three-hour average. The permit will require the turbines to be fired with pipeline-grade natural gas with SO_2 emissions of 9.79 lb/hr, based on

AP-42 (4/00), Table 3.1-2, which is equivalent to 0.005 lb/MMBTU. The auxiliary boiler emissions are 0.006 lb/MMBTU. The backup diesel generator and diesel fire water pump will fire diesel fuel with a maximum sulfur content of 0.05 % by weight. This fuel will produce emissions of approximately 0.05 lbs/MMBTU which is well below the allowable emission limitation of 0.8 lb/MMBTU for liquid fuels.

Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBTU. Equipment burning gaseous fuel is exempt from the opacity monitor requirement, and equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitoring requirement, so the turbines and duct burners do not require such monitoring.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]

This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.2 lb of NO_X per MMBTU. The 2-hr average emission limit of 32.0 lb/hr for NO_x emissions from each combustion turbine with full duct burner firing, represents an equivalent emission rate of 0.014 lb/MMBTU which is far below the standard of 0.2 lb/MMBTU, therefore the combustion turbines will be in compliance. The auxiliary boiler, backup diesel generator, and the diesel fire water pump are below 50 MMBTUH heat input and are, therefore, not subject to this regulation.

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) [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 to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The anticipated diesel tanks will be below the 1.5 psia threshold.

Part 5 limits the VOC content of coatings used in coating lines or operations. This facility will not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.

Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions of VOCs. Temperature and available air must be sufficient to provide essentially complete combustion. The turbines are designed to provide essentially complete combustion of VOCs.

OAC 252:100-41 (Hazardous and Toxic Air Contaminants) [Applicable State Only]

Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2000, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, CC, DD, EE, GG, HH, II, JJ, LL, KK, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, XXX, and are hereby adopted by reference as they exist on July 1, 2000. These standards apply to both existing and new sources of HAPs. NESHAP regulations are covered in the "Federal Regulations" section.

Part 5 is a state-only requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category "A" pollutant above de minimis levels must perform a BACT analysis and, if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant that exceeds the de minimis level do not cause or contribute to a violation of the MAAC.

The emissions of ammonia, formaldehyde, pentane, and sulfuric acid were modeled and shown to be well within the MAAC limits (see Section III). Since formaldehyde is a VOC, BACT for formaldehyde is identical to BACT for VOC as previously shown in the "PSD Review" section. Similarly, BACT for SO_2 constitutes BACT for H_2SO_4 emissions.

OAC 252:100-43 (Sampling and Testing Methods) [Applicable]
All required testing must be conducted by methods approved by the Executive Director under the direction of qualified personnel. All required tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by the AQD.

OAC 252:100-45 (Monitoring of Emissions) [Applicable]
Records and reports as Air Quality shall prescribe on air contaminants or fuel shall be recorded, compiled, and submitted as specified in the permit.

SECTION VI. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The facility is a listed source as a fossil fuel-fired electric plant of more than 250 MMBTU heat input with emissions greater than 100 TPY. PSD review has been completed in Section IV.

NSPS, 40 CFR Part 60 [Subparts Da, Dc, and GG are Applicable]
Subpart Da, Electric Steam Generating Units, affects electric steam generating units with a design capacity greater than 250 MMBTUH constructed after September 18, 1978. Combined cycle gas turbines with such capacity are affected sources only if fuel combustion in the heat recovery unit exceeds the 250 MMBTUH level. The duct burners in the HRSGs are rated at 565 MMBTUH (LHV), so they are subject to Subpart Da. However, since the turbines are subject to NSPS, Subpart GG, they are exempt from this subpart as per §60.40a(b). Emission standards, monitoring requirements, and performance testing are described for PM (opacity), SO_2 and NO_X. The §60.42a standard for PM is 0.03 lb/MMBTU. The maximum PM emissions anticipated from duct burners are approximately 0.027 lb/MMBTU (LHV). This section also contains an opacity standard of no greater than 20% (six-minute average) except for one six-minute period per hour of no more than 27%. Sources using exclusively gaseous fuels are exempt from continuous monitoring of opacity per §60.47a(a).

The §60.43a standard for SO_2 is 1.20 lb/MMBTU. The maximum SO_2 emissions anticipated from the duct burners are approximately 0.006 lb/MMBTU (LHV). Sources using exclusively gaseous fuels are exempt from continuous monitoring of SO_2 per §60.47a(b).
The §60.44a standard for NO_X is 1.6 lb/MW-hour (gross). The maximum NO_X emissions anticipated from the duct burners are approximately 0.0252 lb/MMBTU (LHV) and 0.21 lb/MW-hour (gross). Continuous monitoring of NO_X is required per §60.47a(c).
Further discussion covers supporting tests, defines the Reference Methods to be used and gives reporting requirements. These points will be outlined in the Specific Conditions.
Subpart Dc, Industrial-Commercial-Institutional Steam Generating Units, affects industrial-commercial-institutional steam generating units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989. For gaseous-fueled units, the only applicable standard of Subpart Dc is a requirement to keep records of the fuels used. The 33 MMBTUH (LHV) gas-fired auxiliary boiler is an affected unit as defined in the subpart since the heating capacity is above the de minimis level. Recordkeeping will be specified in the permit.

Subpart GG, Stationary Gas Turbines, affects combustion turbines which commenced construction, reconstruction, or modification after October 3, 1977, and which have a heat input rating of 10 MMBTUH or more. Each of the proposed turbines has a rated heat input of 1,701 MMBTU/hr (LHV) and is subject to this subpart.

EPA guideline document EMTIC, GD-009 advises to use zero for the value of F with gas turbines. So, the lowest NO_X limit is 0.0075% or 75 ppmdv when Y = 14.4. NO_X emission limitation for each turbine is 3.5 ppmdv at 15% O_2 and therefore is more stringent than the Subpart GG standards. Performance testing by Reference Method 20 is required. Monitoring fuel for nitrogen content was addressed in a letter dated May 17, 1996, from EPA Region 6. Monitoring of fuel nitrogen content shall not be required when pipeline-quality natural gas is the only fuel fired in the turbine.

Sulfur dioxide standards specify that no fuel shall be used which exceeds 0.8% by weight sulfur nor shall exhaust gases contain in excess of 150 ppm SO_2. For fuel supplies without intermediate bulk storage, the owner or operator shall either monitor the fuel nitrogen and sulfur content daily or develop custom schedules of fuel analysis based on the characteristics of the fuel supply; these custom schedules must be approved by the Administrator before they can be used for compliance with monitoring requirements. The EPA Region 6 letter referenced above also states that when pipeline-quality natural gas is used exclusively, acceptable monitoring for sulfur is a quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly "stain tube" analysis.

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

NESHAP, 40 CFR Part 63 [Not Applicable At This Time]
There is no current standard that applies to this facility. A MACT standard may be applicable under the source category "Subpart YYYY - Combustion (Gas) Turbines" which is scheduled for promulgation by May 2002. Air Quality reserves the right to reopen this permit as allowed in OAC 252:100-8 if any standard becomes applicable.

The combustion turbines are a listed MACT source category and could potentially be subject to case-by-case MACT requirements. Duct burners associated with HRSGs are exempt from consideration for case-by-case MACT as explained in EPA's May 25, 2000, Interpretive Ruling on this issue. This facility is not a major source of HAPs.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable At This Time]
There will be no regulated substances used, stored or processed at the facility above threshold levels as a result of this project except possibly ammonia. If ammonia will be stored above the applicable threshold, the facility will need to comply with the requirements of this part by the date on which the regulated substance (ammonia) is present above the threshold quantity. 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]
This facility is an affected source since it will commence operation after November 15, 1990, and is not subject to any of the exemptions under 40 CFR 72.7, 72.8 or 72.14. Paragraph 72.30(b)(2)(ii) requires a new source to submit an application for an Acid Rain permit at least 24 months prior to the start of operations. However, Mr. Dwight Alpern, U.S. EPA, has confirmed that this requirement was for the benefit of the regulating agency (Oklahoma DEQ) which can waive this requirement and has done so.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
This part provides for allocation, tracking, holding, and transferring of SO_2 allowances.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
The facility shall comply with the emission monitoring and reporting requirements of this Part.

Acid Rain, 40 CFR Part 76 (NO_X Requirements) [Not Applicable]
This part provides for NO_X limitations and reductions for coal-fired utility units only.

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]
This facility does not produce, consume, recycle, import, or export any controlled substances or controlled products as defined in this part, nor does this facility perform service on motor (fleet) vehicles which involves ozone-depleting substances. Therefore, as currently operated, this facility is not subject to these requirements. To the extent that the facility has air-conditioning units that apply, the permit requires compliance with Part 82.

SECTION VII. COMPLIANCE

Tier Classification And Public Review

This application has been determined to be Tier III based on the request for a construction permit for a new major stationary source that emits 100 TPY or more of pollutants subject to regulation. 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 has option to purchase the land.

The applicant published the "Notice of Filing a Tier III Application" in the *Duncan Banner*, a daily newspaper in Duncan, Stephens County, on August 12, 2001. The notice stated that the application was available for public review at the Duncan Public Library at 815 Ash in Duncan, Oklahoma and the Air Quality Division's main office at 707 North Robinson, Oklahoma City, Oklahoma. The applicant published the "Notice of Draft Permit" in the *Duncan Banner*, a daily newspaper in Duncan, Stephens County, on October 14, 2001. The notice stated that the draft permit was available for public review at the Duncan Public Library at 815 Ash in Duncan, Oklahoma, the Air Quality Division's main office at 707 North Robinson, Oklahoma City, Oklahoma, and on the Air Quality section of the DEQ Web Page: http://www.deq.state.ok.us/. The notice also included notice of the public meeting, which was held on November 15, 2001, at 7:00 p.m. at the Duncan City Council Chambers located at 18 South 7th Street, Duncan, Oklahoma. The permittee requested a change concerning the Permit Memorandum and the Specific Conditions of the permit. The changes were minor in nature, were only to clarify the intent of the permit, and are summarized below. The applicant published the "Notice of Proposed Permit" in the *Duncan Banner*, a daily newspaper in Duncan, Stephens County, on November 16, 2001. The notice stated that the proposed permit was available for public review at the Duncan Public Library at 815 Ash in Duncan, Oklahoma, the Air Quality Division's main office at 707 North Robinson, Oklahoma City, Oklahoma, and on the Air Quality section of the DEQ Web Page: http://www.deq.state.ok.us/. This site is within 50 miles of the Oklahoma – Texas border. The state of Texas has been notified of the draft permit. No comments were received from the state of Texas, the public, or U.S. EPA Region VI during the draft permit public comment period, the public meeting, or the proposed permit comment period.

Comments from the Applicant on the Draft Permit

The applicant requested that the Permit Memorandum and Specific Conditions of the permit indicate at which oxygen (O_2) level the specific VOC emission limit was based on. As indicated in the letter and the application submitted by the applicant, the reference O_2 level for VOC emission limits was based on an O_2 level of 10.4%. The Permit Memorandum and Specific Conditions of the proposed permit were updated to show that the VOC emission limit of 9.7 ppmvw was based on a reference O_2 level of 10.4%.

Fees Paid

Construction permit application fee of $2,000.

SECTION VIII. SUMMARY

The applicant has demonstrated the ability to comply with the requirements of the applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance and enforcement issues concerning this facility. Issuance of the proposed permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Duke Energy Stephens, L.L.C.
Stephens Energy Facility **Permit No. 2001-157-C (PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on July 10, 2001, with additional information submitted on July 9, 2001 and August 10, 2001. The Evaluation Memorandum dated December 6, 2001 explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

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

Each of Two Combustion Turbines With Duct Burner Firing				
Pollutant	**lb/hr**	**TPY**	**ppmvd[1]**	**lb/MMBTU**
NO_X	32.0[2]	130.8	3.5[3,4]	
CO	88.1	364.4	16[5]	
VOC	20.6	86.3	9.7[6] ppmvw	
SO_2	14.5	58.7		0.006
PM_{10}	34.5	148.9		
Ammonia	37.3	154.6	10[4,7]	
H_2SO_4	2.4	10.3		

[1] Concentrations are based on parts per million dry volume except as noted.
[2] Two-hour rolling average, based on contiguous operating hours.
[3] NO_x concentrations are limited to 3.5 ppmvd, corrected to 15% O_2, per turbine
[4] 24-hour rolling average, based on contiguous operating hours.
[5] CO concentrations are limited to 10 ppmvd, corrected to 15% O_2, per turbine, without the duct burner firing;
[6] VOC emissions are based on 10.4% O_2;
[7] Ammonia emissions are based on 10% O_2.

Pollutant	**Auxiliary Boiler**		**Backup Diesel Generator**		**Diesel Fire Water Pump**		**Cooling Towers**	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
NO_X	1.7	5.0	10.2	2.6	6.2	1.6	--	--
CO	2.8	8.4	12.6	3.2	1.3	0.3	--	--
VOC	0.5	1.6	1.5	0.4	0.5	0.1	--	--
SO_2	0.2	0.6	0.3	0.1	0.4	0.1	--	--
PM_{10}	0.3	1.0	0.6	0.1	0.6	0.2	1.2	5.1

Limits for toxic emissions subject to OAC 252:100-41 are shown below. These authorized levels are predicated upon maximum operating conditions as listed in Specific Condition 1 and use of AP-42 emission factors. Toxics not listed shall not exceed their respective *de minimis* thresholds.

Pollutant	**CAS #**	**Emissions (lb/hr)**
Ammonia	7664417	74.6
Formaldehyde	50000	1.1
Pentane	109660	3.3
Sulfuric Acid	7664939	4.8

2. Compliance with the authorized emission limits of Specific Condition No. 1 shall be demonstrated by monitoring fuel flow to each turbine, each duct burner, the auxiliary boiler, and initial performance testing designed to satisfy the requirements of federal NSPS and to confirm the manufacturer-guaranteed emission factors. Usage of commercial-grade natural gas is limited to 31,262.4 MMSCF per twelve-month rolling period for two combustion turbines, 10,821.0 MMSCF per twelve-month rolling period for two duct burners, and 198 MMSCF per twelve-month rolling period for the auxiliary boiler. Compliance with NO_X limits shall be based on CEM data, and compliance with other limits shall be based on compliance testing, where required. [OAC 252:100-8-6(a)]

3. A serial number or another acceptable form of permanent (non-removable) identification shall be on each turbine. [OAC 252:100-8-6(a)]

4. Upon issuance of an operating permit, the permittee shall be authorized to operate each combustion turbine with associated HRSG, duct burner and cooling tower continuously (24 hours per day, every day of the year). The auxiliary boiler will be limited to 6,000 hours per year. The backup diesel generator and fire water pump are considered insignificant activities and shall be limited to 100 hours each of operation per twelve-month rolling period. [OAC 252:100-8-6(a)]

5. The permittee shall incorporate the following BACT methods for reduction of emissions. Emission limitations are as stated in Specific Condition No. 1. [OAC 252:100-8-6(a)]

a. Each HRSG shall contain a properly operated and maintained Selective Catalytic Reduction System.
b. Each combustion turbine shall be equipped with dry low-NO_X burners.
c. The auxiliary boiler shall be equipped with low-NO_X burners.
d. Emissions from the auxiliary boiler, backup generator and fire water pump engine shall be controlled by properly operating per manufacturer's specifications, specified fuel types and limits as listed in Specific Condition #1.

6. Each turbine is subject to the federal New Source Performance Standards (NSPS) for Stationary Gas Turbines, 40 CFR 60, Subpart GG, and shall comply with all applicable requirements. [40 CFR §60.330 to §60.335]

a. §60.332: Standard for nitrogen oxides
b. §60.333: Standard for sulfur dioxide
c. §60.334: Monitoring of operations
d. §60.335: Test methods and procedures

A quarterly statement from the gas supplier reflecting the sulfur analysis or a quarterly "stain tube" analysis is acceptable as sulfur content monitoring of the fuel under NSPS Subpart GG. Other customary monitoring procedures may be submitted with the operating permit for consideration. Monitoring of fuel nitrogen content under NSPS Subpart GG shall not be required while commercial quality natural gas is the only fuel fired in the turbines.

7. The duct burners are subject to federal New Source Performance Standards, 40 CFR 60, Subpart Da, and shall comply with all applicable requirements. [40 CFR §60.42 to §60.49]

a. 60.42a: Standard for particulate matter
b. 60.43a(b): Standard for sulfur dioxide
c. 60.44a(a): Standard for nitrogen oxides
d. 60.47a: Emission monitoring
e. 60.48a: Compliance determination procedures and methods
f. 60.49a: Reporting requirements

8. The permittee shall maintain a record of the amount of natural gas burned in the auxiliary boiler for compliance with NSPS Subpart Dc. [NSPS §60.48c(g) and 60.13(i)]

9. The fire water pump and backup generator shall be fitted with non-resettable hour-meters. [OAC 252:100-8-6(a)]

10. The permittee shall comply with all acid rain control permitting requirements and SO_2 emissions allowances and SO_2, NO_X, and O_2 continuous emissions monitoring and reporting. SO_2 emissions will be monitored in accord with Part 75, Appendix D.

11. Within 60 days of achieving maximum power output from each turbine generator set, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with Subpart GG for the combustion turbines, Subpart Da for the duct burners, and Subpart Dc for the auxiliary boiler. [OAC 252:100-8-6(a)]

The permittee shall conduct NO_x, CO, PM_{10}, and VOC testing on the turbines at the 60% and 100% operating rates, with testing at the 100% turbine load to include testing at both a 70% and 100% duct burner operating rate. NO_x and CO testing shall also be conducted on the turbines at two additional intermediate points in the operating range, pursuant to 40 CFR §60.335(c)(2).

Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

The permittee shall conduct sulfuric acid mist testing on the turbines and duct burners at the 100% operating rate of both the turbine and duct burner. Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

The permittee shall conduct formaldehyde testing on the turbines at the 50% and 100% operating rates, without the duct burners operating.

The permittee may report all PM emissions measured by USEPA Method 5 as PM_{10}, including back half condensable particulate. If the permittee reports USEPA Method 5 PM emissions as PM_{10}, testing using USEPA Method 201 or 201A need not be performed.

Performance testing shall be conducted while the new units are operating within 10% of the desired testing rates. Testing protocols shall describe how the testing will be performed to satisfy the requirements of the applicable NSPS. The permittee shall provide a copy of the testing protocol, and notice of the actual test date, to AQD for review and approval at least 30 days prior to the start of such testing.

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

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4:	Determination of Moisture in Stack Gases.
Method 5:	Determination of Particulate Emissions from stationary sources.
Method 8:	Sulfuric Acid Mist.
Method 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
Method 6C	Quality Assurance procedures (Range and Sensitivity, Measurement System Performance Specification, and Measurement System Performance Test Procedures) shall be used in conducting Method 10.
Method 20:	Determination of Nitrogen Oxides and Oxygen Emissions from Stationary Gas Turbines.
Method 25/25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.
Method 201/201A	Determination of PM_{10} Emissions
Method 320:	Vapor Phase Organic & Inorganic Emissions by Extractive FTIR

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

a. Operating hours for each auxiliary boiler, backup generator and diesel fire water pump (monthly and 12-month rolling totals).
b. Total fuel consumption for each turbine, each heat recovery steam generator duct burner, and the auxiliary boiler (monthly and 12-month rolling totals).
c. Sulfur content of natural gas and each delivery of diesel fuel (supplier statements or quarterly "stain-tube" analysis).
d. Diesel fuel consumption for the backup generator and diesel fire water pump (12-month rolling totals).
e. CEMS data required by the Acid Rain program.
f. Records required by NSPS, Subparts Da, Dc, and GG.

13. When monitoring shows concentrations in excess of the ppm or lb/MMBTU (LHV) limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions including during start-up, shutdown, and malfunction of air pollution control equipment. Due to technological limitations on emissions during turbine start-up and shutdown, the owner or operator may submit an initial written notification of this condition and thereafter immediate notice and quarterly reports as provided in Paragraph 3.1(b)(2). Requirements for periods of other excess emissions include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions. [OAC 252:100-9]

14. The permittee shall apply for a Title V operating permit and an Acid Rain permit within 180 days of operational start-up.

15. No later than 30 days after each anniversary date of the issuance of this permit, 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. The following specific information is required to be included: [OAC 252:100-8-6 (c)(5)(A) & (D)]

a. Summary of monitoring, operation and maintenance records required by this permit
b. Executive summary of quarterly RATA reports

Duke Energy Stephens, L.L.C.
Attn: Mr. William G. Collins
Manager, Environmental Licensing
5400 Westheimer Ct.
Houston, TX 77053

Re: Permit Number 2001-157-C (PSD)
Duke Energy Stephens, L.L.C.
Duke Energy Stephens Facility
Section 32-T1S-R7W, Stephens County

Dear Mr. Collins:

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

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

Sincerely,

Eric L. Milligan, P.E.
New Source Unit
AIR QUALITY DIVISION

Enclosures

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

Date ____________________________ Permit No. 2001-157-C (PSD)

Duke Energy Stephens, L.L.C., having complied with the requirements of the law, is hereby granted permission to construct the Stephens Energy Facility in Stephens County, Oklahoma,

subject to the following conditions, attached:

[X] Standard Conditions dated October 17, 2001

[X] Specific Conditions

_______________________________________ Executive Director

DEQ Form No. 885
Revised 7/93