OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **October 17, 2001**

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

THROUGH: Phillip Fielder, P.E., New Source Permits Unit
Eric Milligan, P.E., New Source Permits Unit

THROUGH: Peer Review

FROM: Jian Yue, P.E., Environmental Engineer

SUBJECT: Evaluation of Permit Application No. **2000-278-C (PSD)**
Energetix
Webbers Falls Energy Facility
Section 19-T13N-R19E, Muskogee County

SECTION I. INTRODUCTION

Energtix submitted an application for a construction permit on November 20, 2000. The proposed facility (SIC Code 4911) will consist of three combined cycle gas turbines with duct burners and heat recovery steam generators producing a nominal total of 850 MW. Since the facility will have emissions in excess of 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 project will begin operations with simple cycle turbines. These simple cycle turbines will be upgraded to combined cycle units with the addition of the heat recovery steam generators (HRSG), the steam turbine, duct burners, and cooling towers. Upon completion of the proposed construction, the facility will consist of three natural gas-fired combined cycle combustion turbine generators with duct burners, three heat recovery steam generators, one natural gas-fired auxiliary boiler, two emergency diesel generators, one diesel fire 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 three gas turbines will be a General Electric PG7241FA combustion turbine with a nominal heat input of 1,801 MMBTUH. The combustion turbines are designed to operate in the dry low-NOx (lean pre-mix) mode at loads from 70 percent up to base load rating.

The three heat recovery steam generators (HRSGs) will take advantage of the hot exhaust gases from the combustion turbines and duct burners (497 MMBTUH each) 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 30 MMBTUH to augment turbine start-up. The boiler will fire natural gas exclusively and will be limited to an annual operation of 3,000 hours.

The emergency diesel generator and the diesel fire pump will be used as backup systems in the event that there is a power outage. The emergency diesel generator is rated at 1,000 kW and the diesel fire pump is rated at 300 BHP. These internal combustion engines will be limited to a maximum annual operation of 500 hours.

The facility will utilize one cooling tower consisting of approximately 14 cells. The cooling tower will provide cool water to the condensing steam turbine. The water to be used in the cooling tower will come from the Arkansas River.

SECTION III. SCOPE OF REVIEW AND EMISSIONS

Since the facility will exceed the 100 TPY PSD threshold for NOx, 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, fuel gas heater, emergency diesel generators, diesel fire 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 emergency generator and fire 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 tank. Ammonia is supplied to the SCR process in amounts slightly above the stoichiometric requirement, so there are 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 ppm @ 15% O_2 for gas turbine with duct burner firing; CO: 9 ppm; Ammonia slip: 7 ppm; SO_2: 0.002 lb/MMBTU; VOC: 2.5 ppm for turbine alone, 11.9 ppm for turbine with duct burner firing) and continuous operation. Auxiliary boiler emissions are based on manufacturer's data and 3,000 hours/year operation. Emergency diesel generator and diesel fire pump emissions are based on AP-42 (10/96), Section 3.3 and 500 hours/year operation.

Turbine and Duct Burner Emissions

Pollutant	Single Turbine		Turbine with Duct Burner		Three Turbines with Duct Burners	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
NO_X	22.7	99.4	51.2	224	153.7	672
CO	30.1	131.84	76.2	333.8	228.6	1001.4
VOC	2.6	11.39	14.5	63.6	43.5	190.8
SO_2	3.60	15.78	4.59	20.12	13.77	60.36
PM_{10}	18	78.84	27.9	122.2	83.7	366.6
Lead	0.0001	0.004	0.0001	0.004	0.003	0.013

Calculated Facility Wide Emissions

Pollutant	**Three CTGs w/ Duct Burners**		**Auxiliary Boiler**		**Emergency(1) Diesel Generator**		**Diesel(1) Fire Pump**		**Cooling(2)(3) Tower**		**Total Maximum (4) Annual Emissions**	
	lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
NO_X	153.7	672	1.50	2.25	41.90	10.45	4.69	1.17	--	--	201.79	685.87
CO	228.6	1001.4	2.47	3.71	9.03	2.26	1.01	0.25	--	--	241.11	1,007.6
VOC	43.5	190.8	0.16	0.24	3.42	0.86	0.38	0.10	--	--	47.46	192
SO_2	13.2	57.3	0.02	0.03	2.76	0.69	0.31	0.08	--	--	16.29	58.1
PM_{10}	83.7	366.6	0.23	0.34	2.95	0.74	0.33	0.08	3.8	16.64	91.01	384.4
Lead	0.003	0.013	--	--	--	--	--	--	--	--	0.003	0.013

(1) Emergency Diesel Generator (1,000 kW) and Diesel Fire Pump (300 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) Particulate matter emissions are considered to be Total Suspended Particulate. PM_{10} emissions are negligible.
(4) Total Emissions includes the total emissions for three turbines, three duct burners, one auxiliary boiler, one cooling tower, one emergency diesel generator, and one diesel fire pump.

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 (7 ppm). Sulfuric acid mist emissions are based on the applicant's assumption that 5% of SO_2 from the combustion turbine and 10% of SO_2 from the duct burner 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 (7/1998), Table 1.4-3 and 1.4-4.

Hazardous Air Pollutants (HAPS) 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	**63.21**	**276.86**
*1,3-Butadiene	106990	A	0.57	0.60	0.002	0.01
*Acetaldehyde	75070	B	1.1	1.2	0.204	0.892
*Acrolein	107028	A	0.57	0.60	0.033	0.143
*Arsenic	7440382	A	0.57	0.60	0.000	0.001
*Benzene	71432	A	0.57	0.60	0.064	0.280
Butane	25167673	NS	--	--	2.705	11.846
*Cadmium	7440439	A	0.57	0.6	0.001	0.006
*Chromium	7738945	A	0.57	0.6	0.002	0.008
*Dichlorobenzene	541731	B	1.1	1.2	0.002	0.007
Ethane	74840	NS	--	--	3.992	17.486
*Ethylbenzene	100414	C	5.6	6.0	0.163	0.714
*Formaldehyde	50000	A	0.57	0.60	**0.789**	**3.457**
*Hexane	110543	C	5.6	6.0	**2.318**	**10.153**
*Naphthalene	91203	B	1.1	1.2	0.007	0.032
*PAHs	**	A	0.57	0.60	0.011	0.049
Pentane	109660	C	5.6	6.0	**3.348**	**14.666**
Propane	74986	NS	--	--	2.061	9.025
*Propylene Oxide	75569	A	0.57	0.60	**0.148**	**0.647**
Sulfuric acid	7664939	A	0.57	0.6	**1.29**	**5.65**
*Toluene	108883	C	5.6	6.0	0.667	2.92
*Xylene	1330207	C	5.6	6.0	0.326	1.428

* 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 Gas Plant (Permit No. 2000-090- C (PSD)). These concentrations were derived from the concentrations in the raw feed water at that plant. Since the Webbers Falls plant has one less turbine than the Arcadia facility, there is about 2 MGD less water to process, and since Arcadia's emissions were modeled and found under de minimis levels, this facility is assured to be under the de minimis levels.

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 Ambient Air Concentration (MAAC). ISCST3 modeling was conducted for each toxic based on 1987 meteorological data and indicated the facility would be in compliance with each MAAC. Since the resulting maximum predicted concentrations were below 50% of the MAAC, no more modeling is required.

Pollutant	**CAS #**	**MAAC ($\mu g/m^3$)**	**Emissions (lb/hr)**	**Estimated Impact ($\mu g/m^3$)**
Ammonia	7664417	1,742	63.21	3.02
Formaldehyde	50000	12	0.789	0.039
Hexane	110543	17,628	2.318	0.15
Pentane	109660	35,000	3.348	0.21
Propylene Oxide	75569	500	0.148	0.007
Sulfuric Acid	7664939	10	1.29	0.06

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	685.87	40	Yes
CO	1,007.6	100	Yes
VOC	192	40	Yes
SO_2	58.1	40	Yes
H_2SO_4	5.65	7	No
PM/PM_{10}	384.4	25/15	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), sulfur dioxide (SO_2), carbon monoxide (CO), particulates less than or equal to 10 microns in diameter (PM_{10}), and volatile organic compounds (VOC). 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, emergency diesel generators, diesel fire 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. Energetix 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's 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^{TM}

SCONOX^{TM}, 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 600 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 higher the gas turbine inlet temperature, 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 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°F - 2,000°F) 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°F.

b) Technical Feasiblility of The Contol 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™ 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™ on its 800 MW combined cycle plant in California.

XONON™

There is currently one field installation of the XONON™ 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™) has a collaborative commercialization agreement with General Electric Power Systems, committing to the development of XONON™. In conjunction with General Electric Power systems, the XONON™ 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 NOx 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 - 5 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$_X$™

The only known commercial applications of Thermal DeNO$_X$™ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800 °F. There are no known applications on or experience with combustion turbines. Temperatures of 1,800 °F 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™ provides the highest level of NO_x reduction and there are no significant environmental impacts from SCONOX™ applications. However, SCONOX™ 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 Webber Falls facility.

The next most effective control technology for NOx is SCR, which is proposed by the applicant to satisfy BACT requirements. Thus, use of SCR with DLN combustors is selected such that the following limitations are met:

NO_x:	3.5 ppmvd @15% O_2 (annual average), with duct burners firing
Ammonia slip:	7 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. 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. Due to the intermittent use of this boiler, the use of low-NO_X burners is acceptable as BACT for NO_X control of the auxiliary boiler, without further analysis.

3. Emergency Diesel Generator And Diesel Fire Pump

An uncontrolled NO_X emission of 4.41 lbs/MMBTU for the emergency diesel generator and 4.39 lbs/MMBTU for the diesel fire pump is based on engine design and is 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.

<u>CO BACT Review</u>

1. Combustion Turbines and Duct Burners

The CO emission rate under maximum load conditions will be limited to 9 ppmvd for the combustion turbine alone when firing natural gas (15.4 ppmvd with duct burner). 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. There are no adverse economic, environmental or energy impacts associated with the proposed control alternative. Thus good combustion practices/design, 9 – 15.4 ppm, are proposed as BACT for CO emissions from the combustion turbines.

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 intermittently operated facilities 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 0.082 lb/MMBTU. Thus, boiler design and good operating practices are proposed as BACT for controlling the CO emissions from the auxiliary boiler.

3. Emergency Diesel Generator And Diesel Fire Pump

The control technologies for CO emissions evaluated for use on the emergency diesel generators and the diesel-powered fire 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 proposed as BACT for controlling the CO emissions from the emergency diesel generators and the diesel-powered fire pump. Good combustion practices are proposed as BACT resulting in CO emissions of 0.95 lb/MMBTU. The proposed BACT will not have any adverse environmental or energy impacts.

SO_2 BACT Review

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 Webbers Falls Energy Facility will utilize pipeline-quality natural gas in the turbines and duct burners. The maximum estimated SO_2 emissions would be 0.002 lb/MMBTU 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. Emergency Diesel Generator And Diesel Fire 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 % Sulfur) represents BACT for the diesel engines.

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 of 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 Webbers Falls Energy Facility will not employ a CO catalyst, such collateral reductions in VOC are not available.

Since an oxidation catalyst was shown to not be cost effective for control of 131.84 tons/yr/turbine of CO, it could not be cost effective for control of at most 44 percent (BACT level of control) of 11.39 TPY of VOC per turbine. An oxidation catalyst cannot, therefore, be considered to represent BACT for VOC emissions from the Webbers Falls Power Plant. Therefore, good combustion practices and DLN technology are concluded to represent BACT for VOC controls for the Webbers Falls Energy Facility gas turbines.

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 intermittently operated facilities is prohibitive. However, optimizing boiler-operating conditions will minimize VOC emissions. The maximum estimated VOC emission rate is 0.005 lbs/MMBTU. Thus, boiler design and good operating practices are proposed as BACT for controlling VOC emissions from the auxiliary boilers. The proposed BACT will not have any adverse environmental or energy impacts.

3. Emergency Diesel Generator And Diesel Fire 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>PM_{10} BACT Review</u>

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 0.01 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

0.0074 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. Emergency Diesel Generator And Diesel Fire 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 0.31 lbs/MMBtu for the generator and the fire pump is estimated for this proposed BACT. The proposed BACT will not have any adverse environmental or energy impacts. DEQ agrees that combustion control and good engine design is 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 3.8 lb/hr is proposed 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 Pump (permit limit)
NOx	SCR with dry low-NOx combustors (3.5-5 ppm @ 15% O_2 and 7 ppm ammonia slip)	low Nox burner (1.5 lb/hr)	good engine design (41.9/4.69 lb/hr)
CO	good combustion control (9 ppm @ 15% O_2)	good combustion practice (2.47 lb/hr)	good engine design (9.03/1.01 lb/hr)
SO_2	low sulfur fuel (natural gas, 8.49 lb/hr)	low sulfur fuel (natural gas, 0.02 lb/hr)	0.04% sulfur diesel (2.76/0.31 lb/hr)
VOC	Good combustion practice	boiler design and good operating practices	good engine design
PM_{10}	good combustion control, use of natural gas (8.9 lb/hr)	good combustion practice (0.23 lb/hr)	good engine design, (20% opacity)

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.

Modeling Methodology

The air quality modeling analyses employed USEPA's Industrial Source Complex (ISC3) model (USEPA, 1995a). The ISC3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash (40 CFR 40465-40474).

The ISCST3 model (Version 00101) was used for all pollutants. The regulatory default option was selected such that USEPA guideline requirements were met.

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 NOx concentrations in an area. The ambient impacts analysis utilized these tables from "VOC/NOx Point Source Screening Tables" (Richard Scheffe, OAQPS, September, 1988). The Scheffe tables utilize increases in NOx and VOC emissions to predict increases in ozone concentrations.

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 ($h_b + 1.5\ l_b$) 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 (four 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 five years (1986-1988, 1990, 1991) of hourly surface observations from the Tulsa, Oklahoma, National Weather Service Station (Tulsa International Airport) and coincident mixing heights from Oklahoma City (1986-1988) and Norman, Oklahoma (1990 and 1991). 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 Tulsa 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 receptor grid for the ISC3 dispersion model was designed to identify the maximum air quality impact due to the proposed power plant. Several different rectangular grids made up of discrete receptors were used in the ISCST3 modeling analysis. The receptor grids are made up of 100 meter spaced fine receptors, 500 meter spaced medium receptors and 1,000 meter spaced coarse receptors. Medium grid receptors were used to locate the maximum impact areas. The scenarios were then reevaluated placing fine grid receptors in maximum impact areas to arrive at a final maximum impact. All receptors were modeled with actual terrain based on the proposed plant location. The terrain data was taken from United States Geologic Society (USGS) and Digital Elevation Model (DEM) data. This data was obtained in the USGS Spatial Data Transfer Standard (SDTS) and converted to the normal DEM format using a translation program. The DEM files were then used to derive the terrain elevation data with the BREEZE software terrain import function. An interpolation technique is used to match terrain heights to each individual receptor. The "highest" interpolation technique was chosen. It selects the highest of the four terrain elevations encompassing each object. This generates the most conservative estimates for grid spacing greater than 60 meters. All building, source location, and terrain data were based on the NAD27 datum.

<u>Stack Parameters and Emission Rates</u>

The stack emission rates and parameters needed for the proposed power plant included each of the three exhaust stacks of the three 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	Ft	°F	Ft/sec	Ft
Turbine No.1	288610	3940829	173.7	195	174	51.41	19
Turbine No.2	288651	3940829	173.7	195	174	51.41	19
Turbine No.3	288692	3940829	173.7	195	174	51.41	19
Aux. Boiler	288537	3940876	173.7	80	300	29.99	2

CW Tower 01	288459	3940803	172.5	68	110	25	34
CW Tower 02	288459	3940820	172.5	68	110	25	34
CW Tower 03	288459	3940836	172.5	68	110	25	34
CW Tower 04	288459	3940853	172.5	68	110	25	34
CW Tower 05	288459	3940869	172.5	68	110	25	34
CW Tower 06	288459	3940886	172.5	68	110	25	34
CW Tower 07	288459	3940902	172.5	68	110	25	34
CW Tower 08	288459	3940919	172.5	68	110	25	34
CW Tower 09	288459	3940935	172.5	68	110	25	34
CW Tower 10	288459	3940952	172.5	68	110	25	34
CW Tower 11	288459	3940968	172.5	68	110	25	34
CW Tower 12	288459	3940985	172.5	68	110	25	34
CW Tower 13	288459	3941001	172.5	68	110	25	34
CW Tower 14	288459	3941018	172.5	68	110	25	34

Emission Rates				
Source	**CO**	**SO_2**	**PM_{10}**	**NO_X**
	lb/hr	lb/hr	lb/hr	lb/hr
Turbine No.1[1]	76.2	4.4	27.9	73.2[4]
Turbine No.2[1]	76.2	4.4	27.9	73.2[4]
Turbine No.3[1]	76.2	4.4	27.9	73.2[4]
Auxiliary Boiler	2.47	0.02	0.23	1.5
CW Tower Cells[3]	--	--	3.78	--

(1) Includes the CTG and the duct burner.
(2) Auxiliary Boiler emissions are limited to 3,000 hours per year.
(3) Emissions are evenly spread across 14 cells (emissions points).
(4) Modeling was originally conducted at this higher emission rate, since compliance was demonstrated new modeling is not required

Modeling Results

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	0.89	1
CO	8-hour	1986	23.71	500
	1-hour	1987	79.22	2000
PM_{10}	Annual	1990	0.48	1
	24-hour	1987	4.50	5
SO_2	Annual	1991	0.07	1
	24-hour	1987	0.64	5
	3-hour	1991	1.99	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 0.0076 ppm. Based on a fourth high (design) monitored concentration for the years 1998, 1999 and 2000 of 0.102 ppm from the Glenpool Monitor (401430174-1), 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 Muskogee Monitoring site (No. 401010160-1) located 18 km north and 26.2 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	**$\mu g/m^3$**	**$\mu g/m^3$**
NO_2	Annual	14	0.89
CO	8-hour	575	21.28
PM_{10}	24-hour	10	4.50
SO_2	24-hour	13	0.64
VOC	100 TPY of VOC		192.3 TPY VOC

1998 Monitoring Data Summary	
Monitor 401010160-1	
Ranking	**Concentration (ppm)**
First High	0.093
Second High	0.091
Third High	0.090
Fourth High	0.088

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 200 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 30 full-time positions will be made available for local hiring after construction. Due to the relatively large population of the area, these positions, which are also expected to be local hires, will not cause additional residents within the area.

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 Muskogee 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 bechmark 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 NOx 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 facility is greater than 100 km from the nearest Class I area, which is the Upper Buffalo National Wilderness Area. No additional evaluations were conducted.

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. These 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 or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility.

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	Maximum Heat Input (HHV) (MMBTUH)	Allowable Particulate Emission Rate	Potential Particulate Emissions
Each Turbine	1,801	0.18	0.0106
Each Duct Burner	497	0.25	0.0031
Auxiliary Boiler	30	0.51	0.0075
Emergency Diesel Generator (3)	<10	0.6	0.31
Diesel Fire Pump	<10	0.6	0.31

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 unit) are subject to opacity limits under NSPS Subpart Da. Thus, they are exempt from the opacity limit at OAC 252:100-25-3. The other emissions units shown in the table above are subject to this subchapter. These units will assure compliance with this regulation by ensuring "complete combustion" and utilizing pipeline-quality natural gas as fuel. 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 emergency 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 emergency diesel generator and diesel fire pump will fire diesel fuel and have maximum sulfur content of 0.04% by weight or 0.04 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 NOx per MMBTU. The 2-hr average emission limit of 51.2 lb/hr for NO_x emissions from each combustion turbine with full duct burner firing, represents an equivalent emission rate of 0.022 lb/MMBTU which is far below the standard of 0.2 lb/MMBTU, therefore the combustion turbines will be in compliance. The auxiliary boiler, emergency diesel generator, and the diesel fire 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. Temperature and available air must be sufficient to provide essentially complete combustion. The turbines are designed to provide essentially complete combustion of organic materials.

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. These requirements 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, hexane, pentane, propylene oxide, and sulfuric acid were modeled and shown to be well within the MAAC limits (see Section III). Based on the level of ammonia, formaldehyde, hexane, pentane, propylene oxide, and sulfuric acid emissions, the demonstration of MAAC compliance, and the low off-site modeled impact, BACT is accepted as no add-on controls.

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 GG, Da, and Dc 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. Since 497 MMBTUH is added by duct burners

in the HRSGs, they are subject to Da. 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. Maximum PM anticipated from HRSG emissions is 0.012 lb/MMBTU. 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. Maximum SO_2 anticipated from HRSG emissions is 0.006 lb/MMBTU. 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 0.20 lb/MMBTU. Maximum NO_X anticipated from HRSG emissions is 0.057 lb/MMBTU. 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 Genrating 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 30 MMBTUH gas-fired auxiliary boiler is an affected unit as defined as in the subpart since the heating capacity is above the deminimis 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 1,801 MMBTU/hr and is subject to this subpart. Standards specified in Subpart GG limit NOx emissions to 87 ppmvd or less. 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.

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 Turbines” which is scheduled for promulgation by May 2002. Air Quality reserves the right to reopen this permit 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. The facility emits 10.15 TPY of hexane which all come from duct burners.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
There will be no regulated substances used, stored or processed at the facility above threshold levels as a result of this project. 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 Muskogee Daily Phoenix*, a daily newspaper in Muskogee County, on November 22, 2000. The notice stated that the application was available for public review at the Warner City Hall, located at 211 8th Street, Warner, Oklahoma and the DEQ Office at 707 North Robinson, Oklahoma City, Oklahoma. The applicant also published the "Notice of Draft Permit and Public Meeting" in *The Muskogee Daily Phoenix* on July 14, 2001. The public meeting on the draft permit was held at the Warner school gymnasium, in Warner, Oklahoma, on August 14, 2001. The Cherokee Nation requested an extension of the public comment period, and it was granted for a week at the public meeting. Comments were received on the draft permit by the public. A response to those comments is provided below.

Response to Comments on the Draft Permit

The following comments dated August 20, 2001, were received from Mr. Ardyce Briggs.

1. **Comment:** *"What will the pollution that Energetix emits impact my cattle and hay? What will the pollution do to my fescue, clovers, Bermuda and lespedza grasses?"*

   Response: A few common air pollutants are found all over the United States. These pollutants can injure health, harm the environment, and cause property damage.

   Per the Office of Air Quality Planning and Standards (OAQPS), the Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards for pollutants considered harmful to public health and the environment. The Clean Air Act established two types of national air quality standards. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings.

   The EPA Office of Air Quality Planning and Standards (OAQPS) has set National Ambient Air Quality Standards for six principal pollutants, which are called "criteria" pollutants. Units of measure for the standards are parts per million (ppm) by volume, milligrams per cubic meter of air (mg/m^3), and micrograms per cubic meter of air ($\mu g/m^3$).

   Modeling conducted for this project show maximum concentrations of criteria pollutants will be below the significance levels required by the state and federal regulations to protect the public and the environment. In addition, the state of Oklahoma requires an impact analysis for any toxics emitted above a de minimis level. The analysis conducted for this project indicated compliance.

2. **Comment:** *"What is my recourse if pollution invades my grasses? To whom do I report it?"*

   Response: Written or oral complaints can be directed to the complaints unit of Air Quality, Water Quality, and Land Protection Divisions.

3. **Comment:** *"I would like for you to explain again why odors cannot be reported?"*

   Response: There are currently no state or federal regulations which address odor issues.

E-mail to Monty Elder from Lu Ann Stobaugh (lulea74450@yahoo.com), dated August 21, 2001 and forwarded to Jian Yue on 8/22/01

4. **Comment:** *"I would like to state my concerns over the emissions of millions of tons of pollutants into our clean, country air. Oklahoma has always been known for its clean air and beautiful lakes and rivers. There are 19 proposed power plants in the state of Oklahoma alone. When will somebody finally stop them? How many plants are too many? Who will decide? I hope something is done to preserve our great state before it is too late!"*

   Response: EPA has delegated to the Oklahoma Department of Environmental Quality, Air Quality Division the responsibility to enforce the Clean Air Act within the State of Oklahoma. The Division is required by law to issue a permit to an applicant who meets all legal requirements.

The following comments were taken from the transcript of the public meeting held on August 14, 2001, 6:30 pm in the Warner School Library.

Ms. Shirley Haney

5. **Comment:** *"...I am wondering if there will be mercury emitted in this particular matter? And I would like to know what the amount would be."*

   Response: According to AP-42 emission factors, mercury emissions produced by the duct burners are insignificant (0.001 TPY for this project).

Mr. Steve Croftcheck

6. **Comment:** *"...I was wondering how much is too much sulfur dioxide? How much is too much NOx? And how much is this power plant going to produce?"*

   Response: Emission amounts produced by this power plant is listed on page 3 of the permit memorandum. Modeling results show the maximum concentrations of the criteria and toxic pollutants will be below the significance levels required by the state and federal regulations to protect the public and the environment. The Division is required by law to issue a permit to an applicant who meets all legal requirements.

7. **Comment:** *"…We also heard about the 19 other power plants. And is that an accumulative factor? Is that something that's going to be kind of rolled into this proposal?"*

Response: This permit deals specifically with the Webbers Falls power plant. However, air quality impact analysis (see pages 18-25 in the permit memorandum) addresses the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources or nearby sources of air pollution and the modeled ambient impact caused by the applicant's proposed emissions increase and associated growth. The location of such nearby sources could be anywhere within the impact area or an annular area extending 50 kilometers beyond the impact area.

8. **Comment:** *"How are all those power plants in Eastern Oklahoma or in Oklahoma going to affect our lakes and rivers and ponds?"*

   Response: The DEQ AQD's authority is confined to the issuance of air quality permits. However, each facility is required to meet Acid Rain Standards etc.

<u>Mrs. Karen Croftcheck</u>

9. Comment: *"I want to know more about the ammonia slip. Who is monitoring the ammonia slip? How can that be monitored from Tulsa or from wherever it can be monitored, and who is watching out for the Keefeton/Warner area, even Muskogee County, with the ammonia slip?"*

Response: Monitoring ammonia is not required by state or federal regulations. However, Calculations of emissions are required annually and emissions are limited by the permit. In addition, since ammonia is a Category C toxic pollutant, compliance with the Maximum Acceptable ambient Concentrations (MAAC) is required. As shown by modeling results listed on Page 5 of the permit memorandum, The MAAC standard for ammonia is 1,742 $\mu g/m^3$, and the estimated ammonia impact is 3.02 $\mu g/m^3$.

10. Comment: *"…I want to know what is allowable."*

Response: Subchapter 41 of Oklahoma Air Pollution Control Rules requires that no person shall cause or permit the emission of any toxic air contaminant in such concentration as to cause or contribute to a violation of the MAAC. The 24-hour MAACs are based upon occupational exposure limits and the level of toxicity. Level of toxicity as defined in OAC 252:100-41 as the most restrictive eight hour time weighted average concentration specified for workroom air selected from either the 1986-1987 Threshold Limit Values and Biological Exposure Indices as adopted by the American Conference of Government Industrial Hygienists; the Recommended Standards for Occupational Exposure set forth in the July, 1985 summary of National Institute for Occupational Safety and Health Recommendations for Occupational Health Standards; or the 1986 Workplace Environmental Exposure Levels set forth by the American Industrial Hygiene Association. Depending upon toxicity level, the MAAC may be one-tenth, one-fiftieth, or one-hundredth of the occupation exposure limit.

The MAAC standard for ammonia is 1,742 $\mu g/m^3$, and the estimated ammonia impact is 3.02 $\mu g/m^3$.

11. **Comment:** *"I've got scientific data that tells me how many parts per million will kill you. But I want to know on a long-term effect, scientifically, what's going to be happening to my community."*

    Response: Please see response to Comment 10. MAAC standard was derived in a very conservative way (one-tenth of the occupation exposure limit for Category C toxics) and the estimated ammonia impact is only 0.2% of the MAAC standard.

12. **Comment:** *"And also from what I've read on the ammonia aspect of the SCR, you know, there's other technologies available for decreasing NOx. And from what I have read, that this is the cheapest, most effective way to do it for this size of plant is how I understood the reading."*

    Response: The permit review process involves a Best Available Control Technology (BACT) analysis. The BACT analysis considers energy, environmental and economic impacts and other costs in determining the maximum degree of pollutant reduction achievable for the proposed source. In no event can the determination of BACT result in an emission limitation, which would not meet any applicable standard of performance under federal laws and regulations. The BACT analysis performed for this facility was done strictly by the guidelines and in accordance with the rules. Please see the analysis in the draft permit memorandum for further detailed explanation.

13. **Comment:** *"And I am wondering why the standard maybe hasn't been upgraded so that ammonia isn't a factor, if it doesn't have to be."*

    Response: It is unclear what is meant by "the standard hasn't been upgraded". Ammonia is a Category C toxic and is subject to Subchapter 41 requirements. Modeling was performed and the results showed compliance with MAAC.

14. **Comment:** *"Fugitive dust. What exactly does that entail and how do they control fugitive dust, the people that are going to live closely around the plant? And does that include the construction phase?"*

    Response: Fugitive dust emissions are addressed in the Standard Conditions of the draft permit. Section XIX condition A paragraph (5) states, "No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards." This standard does intail the construction phase. During normal operations, these sources are not expected to emit any significant fugitive dust.

15. **Comment:** *"Purging the system. I don't understand all that. And who is monitoring that purging? Is that purging part of the whole parts per million tons of NOx and the carbon monoxide and everything that's emitted?"*

    Response: During the startup process, the entire system is purged with condensed air, and often water spray, to remove any residual gases or residues. This is a routine part of startup operations. It is a crucial step in starting up the plant because it removes any remaining potentially explosive gases or harmful residues that may have accumulated in the ductwork, piping or other parts of the system. During the entire process, the oxygen content and explosive gas levels are monitored to ensure safety. This process must be conducted during startup operations to ensure safety, proper operation and prevent damage to system. Purging the system is expected to have very negligible impact on air emissions. The process will involve the use of a high volume of air, or sometimes nitrogen, to push out any residual natural gas or other combustion gases which might remain in the system. These residual gases would be very small in volume and mostly natural gas. Natural gas is primarily methane which is not a regulated air pollutant. Any water used to clean and purge the system would be collected and handled according to the applicable rules and regulations.

16. **Comment:** *"I just wondered if the DEQ will be monitoring this facility later or -- and how often is it monitored?"*

    Response: Acid Rain, 40 CFR Part 75 requires the applicant to install continuous emission monitor system (CEMS) for NOx, CO_2, and fuel. The CEMS will be audited annually to assure accuracy. Quarterly emission data is reported to the State and the EPA electronically. Emission limits are listed in Specific Condition No.1, and are not to be exceeded except during periods of start-up, shutdown or maintenance operations. Such periods may not exceed four hours per occurrence. When monitoring shows concentrations in excess of the ppm and lb/hr limits of Specific Condition No. 1, the owner or operator must comply with the provisions of OAC 252:100-9 for excess emissions during start-up, shut-down, and malfunction of air pollution control equipment. Requirements include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions other than periods of start-up, shutdown or maintenance operations. In addition, DEQ will conduct annual compliance inspection at the facility.

The applicant published the "Notice of Proposed Permit" in *The Muskogee Daily Phoenix*, a daily newspaper in Muskogee County, on September 16, 2001. The notice stated that the permit was available for public review at the Warner City Hall, located at 211 8^{th} Street, Warner, Oklahoma and the DEQ Office at 707 North Robinson, Oklahoma City, Oklahoma. No comments were received from the public or EPA. Information on all permit actions is available for review on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*. This site is not within 50 miles of another states border.

Fees Paid
Construction permit application fee of $2,000.

SECTION III. 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 permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

ENERGETIX
Webbers Falls Energy Facility **Permit No. 2000-278-C (PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on November 20, 2000, with additional information submitted April 27 and June 7, 2001. The Evaluation Memorandum dated October 17, 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 Three Combustion Turbines With Duct Burners				
Pollutant	**lb/hr**	**TPY**	**ppmvd[1]**	**lb/MMBTU**
NO_X	51.2[2]	224	3.5[3]	
CO	76.2	333.8	15.4	
VOC	14.5	63.6	N/A	
SO_2	4.59	20.1	N/A	0.002
PM_{10}	27.9	122.2	N/A	
Lead	0.0001	0.004	N/A	
H_2SO_4	1.29	5.65	N/A	

1 NOx and CO concentrations: parts per million by volume, dry basis, corrected to 15% oxygen
2 two-hour rolling average
3 twelve-month rolling average

Pollutant	Auxiliary Boiler		Emergency Diesel Generator		Diesel Fire Pump		Cooling Towers	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
NO_X	1.50	2.25	41.90	10.45	4.69	1.17	--	--
CO	2.47	3.71	9.03	2.26	1.01	0.25	--	--
VOC	0.16	0.24	3.42	0.86	0.38	0.10	--	--
SO_2	0.02	0.03	2.76	0.69	0.31	0.08	--	--
PM_{10}	0.23	0.34	2.95	0.74	0.33	0.08	3.8	16.64

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	Emissions TPY
Ammonia	7664417	63.21	276.86
Formaldehyde	50000	0.789	3.456
Hexane	110543	2.318	10.153
Pentane	109660	3.348	14.664
Propylene Oxide	75569	0.148	0.648

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 only commercial-grade natural gas is limited to 47,330,280 MMBTU per year for three combustion turbines, 13,061160 MMBTU per year for three duct burners, and 262,800 MMBTUH per year for the auxiliary boiler.
[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 3,000 hours per year. The emergency diesel generator and fire pump are considered insignificant activities and shall be limited to 500 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 SCR.
b. Each combustion turbine shall have dry low-NO_X burners.
c. Emissions from the auxiliary boiler, emergency 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

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 permittee shall comply with all acid rain control permitting requirements and SO_2 emissions allowances and SO_2 and NO_X continuous emissions monitoring and reporting.

10. 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 50% 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

11. 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, emergency generator and diesel fire pump (monthly and 12-month rolling totals).
b. Total fuel consumption for each turbine and heat recovery steam generator duct burner (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 emergency generator and diesel fire pump (12-month rolling totals).
e. CEMS data required by the Acid Rain program.

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

13. No emissions, from other than the turbines and duct burners, and auxiliary boiler, shall be discharged which exhibit greater than 20% opacity except for short-term occurrences not to exceed six minutes in any 60 minutes nor 18 minutes in any 24-hour period; in no case shall opacity exceed 60%. Emissions from the turbines and duct burners, and auxiliary boiler, are subject to NSPS, and thus exempt from this requirement. [OAC 252:100-25]

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

15. 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.

16. When monitoring shows concentrations in excess of the ppm or lb/MMBTU 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, shut-down, and malfunction of air pollution control equipment. Requirements include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions. [OAC 252:100-9]

17. 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

Energetix
Attn: Mr. Ray Mize
100 N. Broadway, Suite 2800
Oklahoma City, OK 73102

Re: Permit Number 2000-278-C (PSD)
Webbers Falls Energy Facility

Dear Mr. Mize:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions which are attached.

Thank you for your cooperation in this matter. If we may be of further service, please contact me at (405) 702-4203.

Sincerely,

Phillip Fielder, P.E.
New Source Permits Unit
AIR QUALITY DIVISION

cc: Muskogee County DEQ Office

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. 2000-278-C (PSD)

Energetix

having complied with the requirements of the law, is hereby granted permission to construct a combined cycle power plant to be known as the Webber Falls Energy Facility near Warner, Muskogee County, OK,

subject to the following conditions, attached:

[X] Standard Conditions

[X] Specific Conditions

______________________________ Executive Director, ODEQ

DEQ Form 885
Revised 7/93