OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **April 29, 2004**

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

THROUGH: David Schutz, P.E., New Source Permit Section

THROUGH: John Howell, E.I., Existing Source Permit Section

THROUGH: Peer Review

FROM: Doug Meese, P.E., New Source Permit Section

SUBJECT: Evaluation of Permit Application No. **2000-090-C (M-4) (PSD)**
Redbud Energy LP
Redbud Power Plant
Section 17, T14N, R1E, Oklahoma County.
Located at the northeast corner of the intersection of Covell and Triple X Roads.

SECTION I. INTRODUCTION

Redbud Energy LP proposes to amend their construction permit, 2002-090-C (M-1) (PSD) which was previously amended (see 2002-090-C (M-3) (PSD))[1], for an electrical generation facility with a peak electrical generating capacity of approximately 1,220 MW, located in Oklahoma County, Oklahoma. This amendment will correct certain inadvertent and/or typographical errors. The Redbud Power Plant will generate electricity for sale to wholesale electric market to meet customer demands. The site and surrounding area is currently pasture land used for grazing livestock. Grade elevation of the main structures and supporting structures will be approximately 1,000 feet above mean sea level (msl).

The facility was issued a permit to construct a nominal 1,100 MW power plant. The company has since been granted a modified construction permit (2000-090-C (M-1) (PSD)) which will incorporate selective catalytic reduction (SCR) for control of emissions of nitrogen oxides (NOx). The revised design will also include heat recovery on all four turbines, and will provide for larger auxiliary units (auxiliary boiler, fire water pump, and emergency generator).

Since the facility will have emissions in excess of the Prevention of Significant Deterioration (PSD) threshold level (100 TPY), the application for modification was a Tier II application and subject to public review. However, the applications for amendment are Tier I and are not subject to public review. Another application for modification, 2000-090-C (M-2) (PSD), was withdrawn.

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1 Changed by administrative amendment dated 04-29-04 in accordance with 252:100-8-7.2(a).

SECTION II. FACILITY DESCRIPTION

The facility will consist of four (4) combustion turbine generators (CTG) with four (4) heat recovery steam generators (HRSG) each equipped with a duct burner, one (1) auxiliary boiler, one (1) diesel emergency generator, one (1) diesel-powered emergency water pump, and cooling towers. The following table compares the capacities as initially permitted to their revised specifications.

Emission Unit	As Initially Permitted	Revised Specifications
Total plant capacity	1,100 MW	1,220 MW
Combustion turbines (GE Model 7FA)	Four 150 MW units (1,698 MMBTUH per turbine)	Four 160 MW units (1,832.3 MMBTUH per turbine)
HRSGs	Four 427 MMBTUH units	Four 599.1 MMBTUH units
Auxiliary boiler (Foster Wheeler AG-5060)	20 MMBTUH	93 MMBTUH
Emergency generator	three 580 HP engines	one 1,818 HP engine
Fire water pump	150 HP engine	300 HP engine
Cooling towers	Four towers, 58,000 GPM	Four towers, 102,000 GPM

The number and size of the cooling towers will remain the same, but a higher water flow (and resultant PM_{10} emission rate) is anticipated. The new emission calculations are based on a drift rate of 0.0005%.

The combustion turbines and auxiliary boiler will be fired exclusively with pipeline-quality natural gas. Water treatment equipment will be required to support the boiler feed water and coolant for the required cooling towers.

SECTION III. EMISSIONS

Emission factors for the turbines are based on manufacturer's guarantees (NOx and CO values for the turbines are based on parts per million by volume, dry basis, corrected to 15% oxygen), and based on 8,760 hours per year operation. The turbine vendor provided emissions estimates for 100% load at 10°F, 60°F, and 98°F. The highest emission rate for each pollutant is listed in the following table. Emissions from the emergency boiler were based on vendor emissions data. Emissions from the diesel generator were based on AP-42 (10/96), Section 3.4, while emissions from the diesel-power water pump were based on AP-42 (10/96), Section 3.3. Emissions from the cooling towers were based on a circulations rate of 102,000 GPM, a drift ratio of 0.0005%, and a total solids content of 3,075 mg/liter. The auxiliary boiler will be limited to 3,000 hours per year. The emergency diesel generator and fire water pump will be limited to 500 hours per year.

The facility exceeds the significance threshold for PM_{10}, NO_x, CO, SO_2, H_2SO_4 and VOC, so the project is subject to full PSD review for these pollutants. Tier II public review, best available control technology (BACT), and ambient impacts analyses are also required.

Pollutant	Emission Factors	Each Combined Cycle Unit	
		lb/hr	TPY
NO_X	3.5 ppm @15% O_2	34.5	151.1
SO_2	0.003 lb/MMBTU	6.9	30.4
PM_{10}	0.012 lb/MMBTU	27.9	122.2
VOC	0.0068 lb/MMBTU	16.2	71.0
CO	17.2 ppm @ 15% O_2	97.5	427.1
H_2SO_4	5% of sulfur	0.6	2.6
Ammonia	7 ppm @15% O_2	25.5	111.7

VOC emissions from the associated diesel storage tanks are negligible.

Unit	Pollutant	Factor (lb/hp-hr)	Emissions lb/hr	Emission TPY
Fire Pump (300 HP)	NO_X	0.031	9.30	2.32
	CO	0.00668	2.00	0.50
	SO_2*	0.0029	0.87	0.22
	VOC **	0.0025	0.75	0.19
	PM_{10}	0.0022	0.66	0.16
Emergency Generator (1,818 HP)	NO_X	0.024	43.63	10.91
	CO	0.0055	10.00	2.50
	SO_2*	0.00324	5.89	1.47
	VOC **	0.000705	1.28	0.32
	PM_{10}	0.0007	1.27	0.32

* based on 0.4% by weight sulfur in fuel.
**sum of exhaust plus crankcase VOC.

Emissions from the cooling towers were calculated assuming a drift ratio (ratio of lost water to total water input) of 0.0005%, a water input of 102,000 GPM per tower, and a total solids content of 3,075 ppm. Combining four towers yields 3.17 lbs/hr or 13.76 TPY of TSP. The application conservatively assumed all TSP was PM_{10}. EPRI's report entitled *User's Manual – Cooling Tower Plume Prediction*, states on page 4-1 that this particulate ranges in size between 20 and 30 micron, thus none of the TSP would be expected to be PM_{10}.

Emissions from the auxiliary boiler are calculated using factors from the vendor. The boiler will be limited to 3,000 operating hours per year.

Unit	Pollutant	Factor (lb/MMBTU)	Emissions lb/hr	Emission TPY
Auxiliary Boiler (93 MMBTUH)	NO_X	0.075	6.98	10.46
	CO	0.070	6.51	9.76
	SO_2	0.0029	0.27	0.40
	VOC	0.0075	0.70	1.05
	PM_{10}	0.00531	0.49	0.74

SUMMARY OF EMISSIONS

Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Unit No. 1	27.9	122.2	6.9	30.4	34.5	151.1	16.2	71.0	97.5	427.1
Unit No. 2	27.9	122.2	6.9	30.4	34.5	151.1	16.2	71.0	97.5	427.1
Unit No. 3	27.9	122.2	6.9	30.4	34.5	151.1	16.2	71.0	97.5	427.1
Unit No. 4	27.9	122.2	6.9	30.4	34.5	151.1	16.2	71.0	97.5	427.1
Auxiliary Boiler	0.49	0.7	0.27	0.4	6.98	10.5	0.70	1.1	6.51	9.8
Cooling Towers	3.17	13.8	--	--	--	--	--	--	--	--
Fire Pump	0.66	0.2	0.87	0.2	9.30	2.3	0.75	0.2	2.00	0.5
Emergency Gen.	1.27	0.3	5.89	1.5	43.63	10.9	1.28	0.32	10.00	2.5
TOTALS	117.19	503.8	34.63	123.70	197.9	628.1	67.53	285.62	408.51	1720.2

EMISSIONS COMPARED TO PSD LEVELS OF SIGNIFICANCE

Pollutant	Emissions, TPY		PSD Levels of Significance, TPY	PSD Review Required?
	Initially Permitted	Modified Application		
NOx	1,660.0	628.1	100	Yes
CO	1,559.0	1,721.2	100	Yes
VOC	171.1	285.6	40	Yes
SO_2	172.4	123.7	40	Yes
PM/PM_{10}	402.2	503.8	25/15	Yes
Lead	0.0036	0.0042	0.6	No
H_2SO_4	5.16	10.2	7	Yes
Ammonia	--	446.8	NA	No

SECTION IV. PSD REVIEW

As shown preceding, the proposed facility will have potential emissions above the PSD significance levels for NOx, CO, SO_2, VOC, H_2SO_4, and PM_{10}, and these are reviewed below. 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 impacts.

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 (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), particulates less than or equal to 10 microns in diameter (PM_{10}), sulfuric acid mist (H_2SO_4), 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 towers. 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. Redbud Energy LP identified these technologies and emissions data through a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as EPA's NSR and CTC websites, recent DEQ BACT determinations for similar facilities, and vendor-supplied information.

<u>NOx BACT Review</u>

The Redbud Power Plant combustion turbine/HRSG units will be subject to a NOx emission limit of 3.5 ppmvd at 15% oxygen utilizing Selective Catalytic Reduction (SCR). There are potential adverse environmental impacts associated with this control technology, primarily from ammonia slip which will be limited to 7 ppm at 15% oxygen. DEQ believes that SCR and DLN with 3.5 ppmvd corrected to 15% oxygen for the turbines and duct burners firing will fulfill the BACT requirement, with consideration given to the technical practicability and economic reasonableness of minimizing emissions. This level of control is similar to many listed in the RACT/BACT/LAER Clearinghouse.

The BACT proposal was reviewed using the EPA RACT/BACT/LAER Clearinghouse on the EPA web site. The search was restricted to turbines with an output of 100 MW or more, permitted after 1994 and located at electric utilities to narrow the field to a manageable number of sources similar to that being evaluated in this analysis. Eighteen sources fit the criteria and had NOx emissions ranging from 2.5 to 25 ppmvd. Some of these evaluations showed oil as a secondary fuel and many had HRSGs but not all of those had duct burners, making comparisons difficult. Units using only DLN as BACT showed emissions ranging between 9 and 25 ppmvd. Units using combinations of DLN and SCR showed emissions ranging between 2.5 and 9 ppmvd. Three of these five units also noted that the DLN/SCR combination was necessary as LAER. Thus, for turbines of the size proposed for this project, the BACT limitation of 3.5 ppmvd is within the range of requirements for other facilities nation-wide.

The following is a list of control technologies, which were identified for controlling NOx emissions from the gas turbines with duct burner firing, and their effective emission levels.

Technology	**Emissions**
Thermal DeNOx	N/A
SCONOX^{TM}	3.5 ppm
Selective Catalytic Reduction w/Dry Low NOx Burners	2.5 -12 ppm
Dry Low NOx Burners (DLN)	9 -25 ppm
NOxOUT Process	22 ppm (65% reduction)
Water/Steam Injection	25 ppm

Thermal DeNOx is a high temperature, selective non-catalytic reduction (SNCR) of NOx using ammonia as the reducing agent. Thermal DeNOx requires the exhaust temperature to be above 1,800^{o}F, and that would require additional firing in the exhaust stream. The only known commercial applications of Thermal DeNOx are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800^{o}F. There are no known applications on or experience with combustion turbines. Temperatures of 1,800^{o}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. Additionally, this option is not feasible due to high capital, operating and maintenance costs, and the need for an additional duct burner system. Therefore, this control technology will be precluded from further consideration in this BACT analysis.

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, but 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 for regeneration and isolated from the flue gas stream with mechanical dampers. 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 water and nitrogen that are emitted from the stack.

SCONOX^{TM} is a very new technology and has yet to be demonstrated for long term commercial operation on large scale combined cycle plants. The catalyst is subject to the same fouling or masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. This has led to reported outages in some cases due to catalyst fouling in the early stages of operations. Long-term performance is even more questionable, since adequate data is unavailable to determine the “aging effect” or degradation in emission control performance over the long term. While this effect is also experienced with conventional SCR catalysts, operating experience with SCRs exists to better predict catalyst life and catalyst replacement cost is far less. Additionally, there are many operational unknowns since available technology would require a significant scale up to accommodate a facility of this size. Due to the extremely high

cost per emission reduction of this control technology (over $26,000 per ton), it is ruled out as a control option and will be precluded from further consideration in this BACT analysis.
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. It can reduce NOx emissions to as low as 9 ppmvd for standard combustion turbines without duct burner firing, and as low as 3-5 ppmvd when combined with DLN combustion (again without duct burner firing). NOx emissions from combustion turbines equipped with DLN combustion and duct burners can be controlled to around 3-5 ppmvd using SCR technology.

An SCR system introduces environmental and health risks to the local area due to the emissions, and potential accidental release, of ammonia. Ammonia gas is an irritant and corrosive to skin, eyes, respiratory tract and mucous membranes. Typical ammonia slip levels for SCR systems are 5–10 ppm in the exhaust stack. Fugitive ammonia emissions are also expected from equipment relating to ammonia loading, storage, and injection into the turbine exhaust gas stream. Additional particulate emissions are due to the formation of ammonium sulfate and ammonium bisulfate. Application of an SCR system would also result in the generation of spent vanadium pentoxide catalyst, which is classified as hazardous waste. An SCR system results in loss of energy due to the pressure drop across the SCR catalyst. Performance loss due to backpressure would result in an energy loss of approximately 5,400 MWh per year. Installation of this complex system could reasonably be expected to cause 50-100 hours of unforced outages, or as much as 100,000 MWh, annually. Although there are several undesirable aspects, SCR is a feasible control technology for this application.

NOxOUT is a process in which aqueous urea is injected into the flue gas stream ideally within a temperature range of 1600 to 1900^{o}F. In addition, there are catalysts available which can expand the range in which the reaction can occur.

The advantages of the system are low capital and operating costs and catalyst which are not toxic or hazardous. Disadvantages include the formation of ammonia from excess urea treatment and/or improper use of reagent catalyst and plugging of the cold end downstream equipment from the possible reaction of sulfur trioxide and ammonia.

The NOxOUT process is limited by the high temperature requirements and has not been demonstrated on any simple cycle or combined cycle combustion turbine. Therefore this control option is not considered technically feasible and will be precluded from further consideration in this BACT review.

Water or steam injection is a control technology that utilizes water or steam for flame quenching to reduce peak flame temperatures and thereby reduce NOx formation. The injection of steam or water into a gas turbine can also increase the power output by increasing the mass throughput, however, it also reduces the efficiency of the turbine. Typically, where applied to combustion turbines with diffusion combustors, water injection can achieve emission levels of 25 ppm while firing natural gas. This control technology is less effective than the proposed technology and will not be discussed further.

Dry Low NOx (DLN) combustors utilize a lean fuel pre-mix and staged combustion to create a diffuse flame. The diffuse flame results in reduced combustion zone temperatures thereby lowering the reaction rate that produces thermal NOx. This combustion strategy focuses on flame temperature for NOx control, and does not result in increased emission rates of other criteria pollutants due to incomplete combustion. It has the additional benefit that no secondary emissions (such as ammonia slip) are associated with this control strategy. Finally, there are no solid or liquid wastes generated due to the operation of DLN burners.

The various Dry Low NOx burner designs are relatively new with commercial development occurring in the last 2 to 5 years. However, because their cost-effectiveness in terms of annualized cost per ton NOx reduced is so favorable, the technology has been rapidly incorporated into new equipment designs. DLN technology is incorporated into the design of the combustion turbines and can achieve NOx emissions as low as 9 ppmvd for the turbines alone. The combined cycle turbine system with DLN combustion and duct burners firing can achieve NOx emissions levels of 15 ppmvd corrected to 15% oxygen.

Since DLN combustors are a passive control, they require no ancillary equipment and make no contribution to a facility's parasitic power requirements. Additionally, DLN combustors do not create or contribute to a pressure drop and heat loss within the combustion turbine.

The boiler design will incorporate low-NOx burners for NOx control, which is common for auxiliary boilers. Due to the intermittent use of this boiler, the use of low-NOx burners is proposed as BACT for NOx control of the auxiliary boiler. The estimated NOx emissions rate is 0.075 lb/MMBTU. No adverse environmental or economic impacts are associated with this NOx control technology.

A review of the RACT/BACT/LAER Clearinghouse indicates that emergency diesel generators and diesel-powered fire pumps have not been required to install additional NOx controls because of intermittent operation. Uncontrolled NOx emissions of 0.024 lbs/hp-hr for the emergency diesel generators and 0.031 lbs/hp-hr for the fire water pump are based on engine design and are proposed as BACT. The proposed BACT will not have any adverse environmental or energy impacts.

CO BACT Review

The CO emission rate under maximum load conditions will be limited to 17.2 ppmvd for the combustion turbine when firing natural gas. 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). In addition, EPA Region VI recently commented for another gas-fired cogeneration plant permit that they expect to see CO at 22 ppm or less for combustion turbines. 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 are proposed as BACT for CO emissions from the combustion turbines.

Oxidation catalysts can achieve 60 percent control of CO emissions in the exhaust stream. An annualized cost of an oxidation catalyst system is estimated at $1,815,000 per combined cycle unit. The oxidation catalyst will eliminate approximately 256.2 TPY CO. These costs and results yield an average of $7,100 per ton controlled, which is excessive.

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

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. CO emission rates are proposed as BACT as 0.00668 lb/hp-hr for the fire water pump and 0.0055 lb/hp-hr for the emergency generator. The proposed BACT will not have any adverse environmental or energy impacts.

SO_2 BACT Review

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 Redbud Power Plant will utilize pipeline-quality natural gas in the turbines and duct burners. The maximum estimated SO_2 emissions would be 0.003 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.

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, they are not common with boilers firing very low sulfur fuels, such as natural gas. FGD systems are not cost effective because the SO_2 emissions are already minimal. The estimated SO_2 emission rate is 0.003 lbs/MMBTU. Thus, the use of an FGD system is not warranted and is rejected as a BACT control alternative.

Therefore, the use of pipeline-quality natural gas is proposed as BACT for the turbines, duct burners, and auxiliary boiler. There are no adverse environmental or energy impacts associated with the proposed control alternative.

A review of the RACT/BACT/LAER Clearinghouse indicates that emergency diesel generators and diesel-powered fire pumps have not been required to install additional SO_2 controls because of intermittent operation. With a maximum of 0.4% by weight sulfur in diesel fuel, SO_2 emissions will be of 0.4 lb/MMBTU. This emission rate is less than the allowable of Subchapter 31 of 0.8 lb/MMBTU. The proposed BACT will not have any adverse environmental or energy impacts.

<u>VOC BACT Review</u>

The most stringent VOC control level for gas turbines has been achieved through advanced low NOx combustors or catalytic oxidation for CO control. According to the list of turbines in the RACT/BACT/LAER Clearinghouse with limits on VOC (see Appendix B), oxidation catalyst systems represent BACT for VOC control in only 2 of the 21 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 which 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 Redbud Power Plant will not employ a CO oxidation catalyst, such collateral reductions in VOC are not available. It is not known whether the catalyst to be used to promote the NOx reducing reaction will also have any measurable effect on enhancing oxidation.

An oxidation catalyst was shown to not be cost effective for control of VOC. Oxidation catalysts can achieve 40 percent control of VOC emissions. An annualized cost of an oxidation catalyst system is estimated at $1,815,000 per combined cycle unit. The oxidation catalyst will eliminate approximately 28.4 TPY VOC. These costs and results yield an average of $65,500 per ton controlled, which is excessive.

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

0.0075 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.

A review of the RACT/BACT/LAER Clearinghouse indicates that emergency diesel generators and diesel-powered fire pumps have not been required to install additional VOC controls because of intermittent operation. Uncontrolled VOC emissions of 0.000705 lbs/hp-hr for the emergency diesel generators and 0.0025 lbs/hp-hr for the fire water pump are based on engine design and are proposed as BACT. The proposed BACT will not have any adverse environmental or energy impacts.

PM_{10} BACT Review

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, the use of natural gas is in itself a highly efficient method of controlling emissions. The maximum estimated PM_{10} emission rate is 0.012 lbs/MMBTU. 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 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.

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 0.00531 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.

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% to 0.004% of cooling water flow, which reduces particulate emissions. Therefore, the use of drift eliminators to attain an air emission rate of 3.17 lb/hr is proposed as BACT for cooling tower particulate emissions. The proposed BACT will not have any adverse environmental or energy impacts.

A review of the RACT/BACT/LAER Clearinghouse indicates that emergency diesel generators and diesel-powered fire pumps have not been required to install additional PM_{10} controls because of intermittent operation. Uncontrolled PM_{10} emissions of 0.0007 lbs/hp-hr for the emergency diesel generators and 0.0022 lbs/hp-hr for the fire water pump are based on engine design and are proposed as BACT. The proposed BACT will not have any adverse environmental or energy impacts.

B AIR QUALITY IMPACTS

The air quality impact analyses were conducted to determine if ambient impacts would result in a radius of impact being defined for the facility for each pollutant. If a radius of impact occurs 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 analyses are required.

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 ISC3 model (Version 99155) consists of two programs: a short-term model (ISCST3) and a long-term model (ISCLT3). The difference in these programs is that the ISCST3 program utilizes an hourly meteorological data base, while ISCLT3 is a sector-averaged program using a frequency of occurrence based on categories of wind speed, wind direction, and atmospheric stability. The ISCST3 model 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 Oklahoma City, Oklahoma, National Weather Service Station (Will Rogers World 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 Oklahoma City and Norman NWS station during this period was 6.2 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 originally modeled with flat terrain. However, in response to comments from the public the applicant has submitted revised modeling, which includes terrain data.

In the final revised modeling, 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. All building, source location, and terrain data were based on the NAD27 datum.

The stack emission rates and parameters needed for the proposed power plant included each of the four exhaust stacks of the four CTs and the exhaust stack of the auxiliary boiler. The modeling was revised in response to public comments to include the emissions from the four proposed cooling water towers. The cooling water towers contribute a minimal amount of particulate matter and toxic 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. The cooling water toxic emission rates were based upon the toxic concentrations in the circulating water. These concentrations were derived from the concentrations in the raw feed water.

STACK PARAMETERS

Source	Easting Meters	Northing Meters	Elevation Meters	Stack Height Feet	Stack Temperature °F	Stack Velocity Feet/sec	Stack Diameter Feet
Turbine No.1	660691	3950288	315	190	170	60.9	18
Turbine No.2	660711	3950341	315	190	170	60.9	18
Turbine No.3	660731	3950394	315	190	170	60.9	18
Turbine No.4	660752	3950449	315	190	170	60.9	18
Auxiliary Boiler	660733	3950363	315	100	309	31.3	4
CW tower cell 1a	660656	3950138	315	45	103	25.1	33
CW tower cell 1b	660651	3950150	315	45	103	25.1	33
CW tower cell 1c	660646	3950164	315	45	103	25.1	33
CW tower cell 1d	660641	3950178	315	45	103	25.1	33
CW tower cell 1e	660635	3950190	315	45	103	25.1	33
CW tower cell 2a	660747	3950180	315	45	103	25.1	33
CW tower cell 2b	660741	3950193	315	45	103	25.1	33
CW tower cell 2c	660736	3950207	315	45	103	25.1	33
CW tower cell 2d	660732	3950221	315	45	103	25.1	33
CW tower cell 2e	660727	3950234	315	45	103	25.1	33
CW tower cell 3a	660779	3950264	315	45	103	25.1	33
CW tower cell 3b	660773	3950274	315	45	103	25.1	33
CW tower cell 3c	660770	3950288	315	45	103	25.1	33
CW tower cell 3d	660765	3950302	315	45	103	25.1	33
CW tower cell 3e	660757	3950320	315	45	103	25.1	33
CW tower cell 4a	660811	3950353	315	45	103	25.1	33
CW tower cell 4b	660806	3950367	315	45	103	25.1	33
CW tower cell 4c	660801	3950380	315	45	103	25.1	33
CW tower cell 4d	660796	3950394	315	45	103	25.1	33
CW tower cell 4e	660791	3950408	315	45	103	25.1	33

EMISSION RATES MODELED

Source	CO lb/hr	SO_2 lb/hr	PM_{10} lb/hr	NOx lb/hr	Ammonia lb/hr
Turbine No.1(1)	97.4	6.9	27.9	35.5(4)	26.75
Turbine No.2(1)	97.4	6.9	27.9	35.5(4)	26.75
Turbine No.3(1)	97.4	6.9	27.9	35.5(4)	26.75
Turbine No.4(1)	97.4	6.9	27.9	35.5(4)	26.75
Auxiliary Boiler	6.5	0.27	0.49	2.4(3)	--
CW Tower Cells(2)	--	--	3.17	--	--

(1) Includes the CTG and the duct burner.
(2) Emissions are evenly spread across 20 cells
(3) 2.4 lb/hr = 3,000 hours / 8,760 hours * 6.98 lb/hr.
(4) Actual emissions at 3.5 ppm, modeled emissions are 49.3 lb/hr for NOx and 29.8 lb/hr for ammonia. Both are conservative estimates.

The modeling results are shown below. The applicant has demonstrated compliance through the application of the NO_2/NOx 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.

COMPARISON WITH AMBIENT LEVELS OF SIGNIFICANCE

Pollutant	Averaging Period	Year	Max. Concentrations ($\mu g/m^3$)	Significance Level ($\mu g/m^3$)
NO_2	Annual	1990	0.71	1
CO	8-hour	1991	28.30	500
	1-hour	1991	83.25	2000
PM_{10}	Annual	1990	0.55	1
	24-hour	1986	4.35	5
SO_2	Annual	1986	0.12	1
	24-hour	1986	1.02	5
	3-hour	1986	2.56	25

The emission rates modeled correspond to a concentration limit of 5ppm for NOx and 10ppm for ammonia. The limits proposed in the draft permit are 3ppm for NOx and 7ppm for ammonia. Even at the higher emission rates, 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.

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 0.0166 ppm. Based on a fourth high (design) monitored concentration for the years 1997, 1998 and 1999 of 0.1 ppm, the projected emissions will not exceed the ozone NAAQS of 0.12 ppm. The ozone impacts were determined using the initially-permitted emission rates, which are very much higher, therefore calculated impacts will be conservative.

Further the applicant participated in the ozone impact study conducted by Environ (March 20, 2000). The study was done to assess the ozone impacts in Oklahoma due to proposed new electrical generating units (EUGs) in the region. CAMx was run for a 1995 Base Case emissions scenario and the model-estimated ozone concentrations were compared with the observed values of a June 1995 ozone episode. EPA has developed a set of model performance goals for ozone to aid in the determination that the model is working adequately. The CAMx model performance statistics for all days of the June 1995 episode meet EPA's model performance goals by a wide margin (usually by over a factor of 2). Additional analysis of the spatial distribution of the predicted and observed 1-hour and 8-hour ozone concentrations revealed that the model exhibited a fairly good job of estimating the spatial patterns of the observed ozone concentrations. CAMx was then applied using the Oklahoma 32, 16, and 4 kilometer grids and the June 18-22, 1995, episode for two future year emission scenarios:

2007 CAA Base Case: Emission in 2007 assuming growth and all Clean Air Act Amendment (CAA) mandated controls.

2007 New OK Sources: 2007 CAA Base Case including emissions from the proposed New Oklahoma Sources added.

The year 2007 was selected for the future-year assessment because growth and control factors were readily available from the Ozone Transport Assessment Group (OTAG) and Dallas-Fort Worth ozone control plan development modeling domain. Emissions from the New Oklahoma City Sources were estimated to not increase ozone in the Tulsa-Oklahoma City area to above the 1-hour ozone standard. Therefore, emissions from the proposed New Sources are estimated not to cause or contribute to any violations of the 1-hour ozone standard in Oklahoma. As the New Oklahoma Sources are estimated to produce changes in peak 8-hour ozone concentrations that are much less than 1 ppb, then they are estimated to have no measurable effect on peak 8-hour ozone concentrations in the Tulsa and Oklahoma City areas.

C 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 existing National Air Monitoring System (NAMS) monitoring site (No. 401091037-1) located 8.4 km south and 22.2 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	μg/m³	μg/m³
NO_2	Annual	14	0.71
CO	8-hour	575	28.30
PM_{10}	24-hour	10	4.35
SO_2	24-hour	13	1.02
VOC	100 TPY of VOC		285.6 TPY VOC

1999 Ozone Monitoring Data Summary

Monitor 401091037-1	
Ranking	**Concentration (ppm)**
First High	0.091
Second High	0.082
Third High	0.081
Fourth High	0.081

D Additional Impacts Analyses

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

Since a small permanent staff of approximately 25 employees will be required by the plant, no significant housing growth is expected. Construction of the plant would not result in an increase in the number of permanent residents. No significant industrial or commercial secondary growth will occur as a result of the project since the number of permanent employees needed is small. Most labor, material, and service requirements are already in place.

Soils and Vegetation

The following discussion will review the projects potential to impact its agricultural surroundings based on the facilities allowable emission rates and resulting ground level concentrations of SO_2 and NOx. SO_2 and NOx were selected for review since they have been shown to be capable of causing damage to vegetation at elevated ambient concentrations.

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.

<u>Visibility Impairment</u>

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.

E 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. An evaluation may be requested if the source is within 200 km of a Class I area. The facility is approximately 171 km northeast of the Wichita Mountains National Wildlife Refuge. The facility is substantially downwind of the Class I area and is not expected to have an impact. 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.

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 252:100-8 (Permits for Part 70 Sources) [Applicable]
<u>Part 5</u> includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and

which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for 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 Emissions 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. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

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

OAC 252:100-19 (Particulate Matter) [Applicable]
Subchapter 19 regulates emissions of particulate matter from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the turbines, auxiliary boiler, diesel fire pump, and emergency diesel generator are subject to the requirements of this subchapter.

Equipment	Maximum Heat Input (MMBTUH per unit)	Allowable Particulate Emission Rate (lb/MMBTU)	Potential Particulate Emissions (lb/MMBTU)
Turbines (4)	1,832	0.15	0.011
Duct Burners (4)	599	0.23	0.008
Auxiliary Boiler	93	0.49	0.0053
Emergency Generator	12.7	0.60	0.100
Diesel Fire Pump	2.1	0.59	0.310

OAC 252:100-25 (Visible Emissions, and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The engines and boilers will remain compliant with this rule by ensuring "complete combustion" or utilizing pipeline-quality natural gas as fuel in the proposed boiler(s). The combined cycle units are not subject to Subchapter 25 since they are subject to an opacity limitation of NSPS Subpart Db.

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 (7/98), Section 3.1, Table 3.1-2, which is equivalent to 0.003 lb/MMBTU. The emergency diesel generator and diesel fire water pump will fire diesel fuel and have maximum sulfur compound emissions of 0.4 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. Since the turbines are limited to natural gas only, they are exempt from the opacity monitor requirement. Based on the pipeline-grade natural gas requirement, the natural gas burned at the site will have less than 0.1 percent sulfur and is, therefore, also exempt from the sulfur dioxide monitor requirement.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
The 2-hr average emission limit of 35.5 lb/hr NOx emissions from each combustion turbine with full duct burner firing, represents an equivalent emission rate of 0.015 lb/MMBTU which is far below the standard of 0.2 lb/MMBTU, therefore the combustion turbines will be in compliance. The auxiliary boiler NOx emission emissions rate of 0.075 lb/MMBTU is also in compliance with the 0.2 lb/MMBTU limitation. The 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. These diesel tanks are below this threshold.
Part 5 limits the VOC content of coatings used in coatings 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]
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, and XXX 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 which exceeds the de minimis level do not cause or contribute to a violation of the MAAC.

Toxic emissions from the turbines are based on AP-42 Table 3.1-3, April 2000, except formaldehyde emissions. Formaldehyde emissions are derived from the EPA database used to establish emission factors for Section 3.1. Toxic emissions from the duct burners and auxiliary boiler were calculated using AP-42 Table 1.4-3 and 1.4-4, July 1998.

Hazardous and/or Toxic Air Pollutants Emissions From Combustion Units

Pollutant	CAS Number	Toxic Category	De Minimis Levels		Emissions	
			lb/hr	TPY	lb/hr	TPY
1,3-Butadiene	106990	A	0.57	0.60	0.003	0.013
Acetaldehyde	75070	B	1.1	1.2	0.270	1.190
Acrolein	107028	A	0.57	0.60	0.043	0.19
Ammonia	7664417	C	5.6	6.0	102.0	446.8
Arsenic	7440382	A	0.57	0.60	0.000	0.000
Benzene	71432	A	0.57	0.60	0.085	0.373
Butane	25167673	NS	--	--	3.601	15.773
Ethane	74840	NS	--	--	0.062	0.093
Formaldehyde	50000	A	0.57	0.60	1.054	4.609
Hexane	110543	C	5.6	6.0	3.110	13.52
Naphthalene	91203	B	1.1	1.2	0.009	0.039
PAHs*	**	A	0.57	0.60	0.019	0.085
Pentane	109660	C	5.6	6.0	4.493	19.529
Propane	74986	NS	--	--	2.765	12.018
Propylene Oxide	75569	A	0.57	0.60	0.197	0.863
Sulfuric Acid	7664939	A	0.57	0.60	2.4	10.2
Toluene	108883	C	5.6	6.0	0.890	3.892
Xylene	1330207	C	5.6	6.0	0.435	1.904

* polycyclic aromatic hydrocarbons ** total group

The cooling water toxic emission rates were based upon the toxic concentrations in the circulating water. These concentrations were derived from the concentrations in the raw feed water.

Toxic Air Pollutants (TAPS) From Cooling Water Towers

Pollutant	Toxicity Category	De Minimis Levels		Emissions	
		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
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.

For emissions of each pollutant which 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 1991 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. Based on the level of formaldehyde, hexane, pentane, and propylene oxide emissions, the demonstration of MAAC compliance, and the low off-site modeled impact, BACT is accepted as no add-on controls.

In response to comments modeling was conducted for all of the toxic pollutants emitted from the cooling water towers. ISCST3 modeling was conducted for each toxic based on five years of meteorological data and indicated the facility would be in compliance with each MAAC. The modeling conducted for Formaldehyde, Hexane, Pentane and Propylene Oxide released from combustion units as well as the modeling conducted for all of the toxic pollutants released from the cooling towers were all based on data corresponding to facility operations at 1,100 MW. The modeling for Ammonia and Sulfuric Acid released from combustion units were based on data corresponding to facility operations at 1,220 MW. Since the resulting maximum predicted concentrations were below 50% of the MAAC, no more modeling is required.

Toxic and/or Hazardous Air Pollutants From Combustion Units

Pollutant	CAS #	MAAC (μg/m³)	Emissions (lb/hr)	Estimated Impact (μg/m³)
Ammonia	7664417	1,742	119.2	4.3
Formaldehyde	50000	12	1.054	0.02
Hexane	110543	17,628	3.110	0.17
Pentane	109660	35,000	4.493	0.24
Propylene Oxide	75569	500	0.197	0.0033
Sulfuric Acid	7664939	10	2.36	0.09

Toxic Air Pollutants (TAPS) From Cooling Water Towers

Pollutants	MAAC (μg/m³)	Emissions (lb/hr)	Estimated Impact (μg/m³)
Antimony	10	0.0021	0.0032
Arsenic	0.02	0.0003	0.0005
Beryllium	0.02	0.0002	0.00026
Cadmium	0.5	2.89×10^{-5}	0.00003
Chromium	0.01	0.0004	0.0005
Copper	4	0.0004	0.0005
Mercury	0.5	7.23×10^{-6}	0.00001
Nickel	0.15	0.0004	0.0006
Selenium	20	9.03×10^{-5}	0.00012
Silver	0.2	7.23×10^{-5}	0.00011
Thallium	1	0.0004	0.0006
Zinc	500	0.004	0.006

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 Air Quality.

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.

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

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

SECTION VI. FEDERAL REGULATIONS

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

NSPS, 40 CFR Part 60 [Subparts Da, Dc, and GG Are Applicable]
Subpart Da affects electric utility steam generating units which have a heat input capacity from fuels greater than 250 MMBTUH which commence construction after September 18, 1978. The emissions resulting from the combustion of fuels in the turbines and duct burners are subject to Subpart Da. As such, these units will be subject to the provision of 40 CFR 60.44a for nitrogen oxides, compliance provisions of 40 CFR 60.46a, emission monitoring requirements of 40 CFR 60.47a, and the reporting requirements of 40 CFR 60.49a.
Subpart Dc 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 93 MMBTUH gas-fired auxiliary boiler is an affected unit as defined in the subpart since the heating capacity is above the de minimis level. Recordkeeping will be specified in the permit.
Subpart GG 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 1,832 MMBTU/hr and are 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 which 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 are three subparts which may affect the proposed project: Subpart YYYY: "Combustion Turbines," scheduled for promulgation by May 2002; Subpart ZZZZ: "Reciprocating Internal Combustion Engines," also scheduled for promulgation by May 2002; and Subpart DDDDD, "Industrial, Commercial and Institutional Boilers and Process Heaters," scheduled for promulgation by May 2002. Air Quality reserves the right to re-open this permit if any of these standards become applicable. Subpart B, "Case-by-Case MACT," is not applicable since the facility will not be a major source of HAPs.

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.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
Until or unless combined cycle operations are initiated, this facility will not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments). The facility will be required to submit a Risk Management Plan on or before the date when ammonia stored on location exceeds the threshold quantity. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

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.

Tier Classification And Public Review

This application has been determined to be Tier I based on the request for an administrative amendment to the modified construction permit for a new major stationary source which emits 250 TPY or more of pollutants subject to regulation. Since this is an amendment of a permit, it is not subject to public review.

SECTION VII. COMPLIANCE

The original permit was challenged at length, including an Administrative Law Hearing. Following the hearing, persons objecting to the facility requested a reconsideration of the permit. DEQ responded to the request for reconsideration with its "Order on Application for Reconsideration of Final Order" dated September 21, 2001. The Order stated that dry low-NOx burners and SCR constitute BACT for a combined-cycle unit, and a permit must provide for NOx emissions of 3.5 ppm or less and ammonia slip of 10 ppm or less, both corrected to 15% oxygen. This permit application is consistent with the Order.

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 II Application" in *The Daily Oklahoman,* in Oklahoma County, on October 6 and October 20, 2001, respectively. The notice stated that the application was available for public review at the Luther City Hall, 119 S. Main, Luther, Oklahoma, the DEQ Office at 707 North Robinson, Oklahoma City, Oklahoma; and on the Air Quality section of the DEQ Web Page: http://www.deq.state.ok.us/ for a period of 30 days. Comments were received on the draft permit by the public. A response to those comments is provided below. This site is not within 50 miles of another states border.

Response to Comments on the Draft Permit

The following comments dated November 16, 2001, were received from Dr. Richard Dawson and Mr. John Hartman. The comments are typed in italics.

1. *In view of the conditions surrounding this permit including the increase in mega wattage, auxiliary boiler changes, almost doubling the circulation of the cooling towers, and the other major changes noted, why is this not a Tier III Application, with greater public safeguards?*

As this is modification of an existing construction permit, the appropriate Tier classification (Tier II) is found at OAC 252:4-7-33(b)(2)(C). Tier III permit review procedures are available for new construction permits and not modifications to existing permits (except modifications to existing incinerators).

2. *What references or data was used to assume the drift rate of 0.0005% is correct?*

Electric Power Research Institute (EPRI) has published a report entitled "User's Manual – Cooling Tower Plume Prediction Code" in April 1984. It states on page 4-4 that none of the TSP would be expected to be PM_{10}.

The cooling tower vendor has provided a guarantee of the 0.0005% drift emissions rate. Their guarantee is contained in documents that are considered confidential and proprietary. ODEQ is not in possession of these documents.

See response to Comment Number (CN) 170, 171, 172, 173 & 174 below.

3. *Since there are 8,760 hours per year, why would you allow the auxiliary boilers to run 3,000 hours per year indirectly adding substantially to the pollution?*

This comment is beyond the scope of the permit modifications being reviewed. The hours of operation of the auxiliary boilers have not been modified or changed. The specific conditions referred to were not changed from the issued permit number 2000-090-C(PSD).

4. *In view of the evidence submitted in the first hearing 17.2 PPM @ 15% oxygen for CO is outrageous for public safety. It does not represent BACT in attainment areas as shown by other permit in attainment areas in many other states including California and Washington. Oklahoma City is near non-attainment. An oxidations catalyst achieves .5 PPM, and simultaneously removes VOC: which are ozone precursors. CO itself is an ozone precursor. Why would the DEQ even consider this high level?*

It should be noted that the issue of BACT was fully litigated during the extensive hearing on the original construction permit. The comment and ensuing response are reiterations of matters that were resolved in the litigation. First, Oklahoma City is not near non-attainment for CO. Second, the comment is implying that BACT in other states (like California) determines what BACT is in Oklahoma. That is not the case. BACT standards are different in each state and geographical location. For example, the BACT standard in California is equivalent to the Lowest Achievable Emission Rate (LAER) standard. LAER is a standard that is not applicable in Oklahoma and therefore, cannot be used to determine BACT in this state. The BACT determination in the permit modification at issue is in full compliance with the BACT standard applicable in Oklahoma. See Section IV (A) <u>CO BACT Review</u> portion of the draft permit memorandum.

5. *The smaller particles PM 2.5 and lower have been shown to be very dangerous to human health. Filled with pesticide from the drift as particulate water or coated with pesticide from the drift covering the particulate matter from the stacks (see references from previous hearings). Please submit medical references showing that even small amounts are not acutely or chronically dangerous to humans or the environment, especially in view of toxicity failures, in spite of evidence to the contrary, (KILLS MINNOWS) at the North Canadian Waste Water Treatment Plant in 1996, 1997, and 1998.*

It should be noted that the issue of the adequacy of the National Ambient Air Quality Standards (NAAQS) to protect public health from alleged collateral health effects was raised and resolved during the extensive hearing on the original construction permit for this facility. This comment and the ensuing response are reiterations of matters resolved in that litigation.

The PSD program requires that emissions from new sources comply with the NAAQS which are health-based standards established by EPA. DEQ evaluated SO_2, PM_{10}, CO, NO_2, VOC and lead emissions in accordance with the PSD program and determined that emissions from the plant will be in compliance with the NAAQS. At the present time, there is no NAAQS for PM2.5.

DEQ is charged with the responsibility to issue permits that are in compliance with the NAAQS. Among other things, the primary and secondary NAAQS are established and periodically revised by EPA after careful consideration of scientific and medical evidence. The NAAQS are then set with a margin of safety adequate to protect public health. In other words, health effects have already been considered by EPA when it established the NAAQS. Modifications to the permit in question have been examined and determined to be in compliance with the current NAAQS for all criteria pollutants and with PSD requirements. DEQ cannot conduct a second evaluation of allegations regarding collateral health issues to determine the adequacy of EPA-established NAAQS. Simply put, the permit review process is not the proper forum for challenging the adequacy of the NAAQS. Please see page 13 of the draft memorandum for the selection of particulate matter BACT and control technology.

6. *Instead of putting the emissions factor to the right of PM10 and VOC in the table on page 3 of the draft permit, they have put "Vendor Guarantees", thus they are not allowing the public to see these values. What are these values and why does DEQ allow the practice of not showing values in the draft permit?*

The draft permit will be modified to include those equivalent emission factors which were previously shown as "Vendor Guarantees".

7. *Since US EPA has consistency defined start up and shut down to be part of the normal operation of the source and, since the US EPA has also consistently included that these emissions "should be accounted for in the design and implementation or the operating procedure for the process and control equipment." Accordingly, it is reasonable to expect the careful planning will eliminate violations on emissions limitations in such periods" see page 57 of "Air Quality Issues". Therefore the question is why hasn't this project, start up and shut down emissions considered in the BACT analysis and all reasonable measures taken to minimize these emissions?*

Specific Condition Number 13 of the proposed permit allows no more than 4 hours per exceedance for start-up and shutdown. When there is an exceedance, the operator must follow requirements of Subchapter 9 of the Oklahoma State regulations. The exceedances must be reported, measured and applied to the permit limits. See Standard Conditions Section II, Reporting of Deviations from Permit Limits of the draft permit.

8. *I can see no evidence in the record that the project start up and shut down emissions were evaluated in the BACT analysis, or that efforts were made to assure that these emissions are appropriately controlled. It is noted in the draft permit on page 3 that under Vendor Guarantees that the PM10 would be 27.9 pounds per hour for each of the four (4)turbines and the VOCs would be 16.2 pounds per hour for each of the four (4) turbines; please note on page 59 for the various power plants listed in California that the number of pounds per hour and thus tons per year is significantly reduced in these areas. Why is it that we are permitting a plant that does not even meet standards of a few power plants in the rest of the United States?*

See response to CN 4, above. It is unclear what document the comment is citing with a reference of page 59. The draft permit has no list of power plants on page 59.

9. *Please note the enclosed article "Effects of Particulate Air Pollution on Children" and references given during the hearing like the Canadian Medical Association on Pollution, on the effects of particulate air pollution on children and adults. In view of the effects on children of the Arcadia plant, why are you not controlling particulate matter and any other pollutants in any way possible considering (a) health effects, (b) economic effects, and (c) other BACT criteria effects? Site references that show either of our references are incorrect including those previously submitted by Dr. Dawson. Saying that criteria pollutants include health effects is not a sufficient answer as the Scientific Advisory board of the EPA validates the 8 hour standards. In lite of this it must be considered that:*

    a. *What the Arcadia plant is currently draft permitted to do will harm public health*
    b. *That the Arcadia plant violates existing pesticide laws as presently draft permitted*
    c. *Is contrary to BACT criteria*

    Please show with references what we are alleging is not true.

See Response to CN 5, above

10. *Why is the DEQ acting an enabler for the power plant to begin construction on their power plant without a valid air permit? Why has DEQ not notified the state Fire Marshall and the County engineer that no permit has yet been issued and therefore, the construction which is now occurring is illegal?*

DEQ denies the allegations contained in this comment and responds that the original construction permit for the facility in question was issued on August 16, 2001.

11. *Citizens for Health and myself were concerned about the health effects of emissions of pesticides in the drift. Specifically these pesticides were identified as diazinon, heptahfor, chlordane and other organo-phosphate pesticides as well as their degradation products and combination products. Does the DEQ have a legal opinion stating that it is not against the law to do this in spite of the whole body of insecticide law previously cited. If the DEQ has any evidence that this is not against the law, could you please cite it here for the public?*

It should be noted that allegations regarding pesticides in the drift from the cooling towers were raised during the extensive administrative proceeding on the original construction permit for this facility. While this issue was not litigated, it was analyzed and information was provided to the Petitioners. This comment and the ensuing response are reiterations of issues previously addressed.

When this issue was raised during the previous litigation, the permit applicant evaluated and modeled the potential emissions of *inter alia* Diazinon and organophosphate pesticides from the cooling towers. The results were the subject of an affidavit dated May 11, 2001. The affidavit was attached as Exhibit "C" to Respondent Redbud's Motion for Summary Judgment and Brief in Support. The Motion and Affidavit were served on then Petitioner Dawson by mail on May 18, 2001.

The following information is taken from the affidavit. The evaluation was done utilizing data from the North Canadian Wastewater Treatment Plant as provided by petitioners. To run the models, it was assumed that all substances, including Diazinon and organophosphate pesticides present in the effluent from the treatment plant would be emitted into the air from the cooling towers. It was also assumed that the amount of these substances would be constant over time at the highest rates shown in the data. Following are the results of the modeling for pesticides and lead:

ESTIMATE OF MAXIMUM CAPACITY COOLING TOWER EMISSIONS DUE TO DRIFT REDBUD ENERGY PROJECT, ARCADIA, OKLAHOMA				
PARAMETER	**Raw Water Concentration (mg/l)**	**Circ Water Concentration (mg/l)**	**Calculated Cooling Tower Drift Emissions (lb/hr)**	
Metals				
Lead	<0.005	<0.025	<0.000102	<0.0004
Pesticides and Organics				
Diazinon	0.00071	0.004	0.000014	0.0001
Chlordane	<0.0002	<0.00100	<0.0000041	<0.0000179
alpha BHC	<0.00005	<0.00025	<0.0000010	<0.0000045
gamma BHC	<0.00005	<0.00025	<0.0000010	<0.0000045
Heptachlor	<0.00005	<0.00025	<0.0000010	<0.0000045
1,2 -Dichlorbenzene	<0.01000	<0.05000	<0.0002042	<0.0008942
Xylene	<0.005	<0.02500	<0.0001021	<0.0004471
Phenol	<0.056	<0.28000	<0.0011433	<0.0050077

These results caused the modeler to conclude the following:

"All of the pesticides and organic chemicals are below the most stringent Class A thresholds of 1,220 pounds per year, not to exceed 0.57 pounds per hour established in OAC 252:100-41-43. These amounts are less than the *de minimis* levels for even the most toxic substances and therefore are not subject to additional regulation under the air toxic regulations, including BACT for air toxics."

OAC 252:100-41 establishes Maximum Allowable Ambient Concentrations (MAAC) for toxic pollutants. 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 is based on 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 on toxicity level, the MAAC level may be one-tenth, one-fiftieth, or one-hundredth of the occupational exposure limit. All toxics (including heavy metals) possibly coming from the cooling towers and fuel burning sources at the facility were evaluated with respect to the MAACs. None of the alleged toxic pollutants exceeded its respective MAAC. Therefore, a health risk assessment was not required. See the results of modeling for these substances beginning on page 24 of the draft permit.

12. *If the DEQ has any evidence that contrary to Dr. Dawson's belief that pesticides are extremely harmful even in small quantities, could you please cite it here for the public? With an increase of particulate matter and more in the way of pollution except for NOx, could the DEQ please answer the questions if heavy metals on the particulate matter would be harmful to health, either acutely or chronically and if they do not believe so, can they please cite some authority that will agree with their position?*

See response to CN 11, above.

13. *On page 5 of the draft permit it explains why the power plant company feels that the BACT limitation of 3.5 PPMVD is within the range of requirements for other facilities nation wide. At the air hearing we clearly showed that the best available control technology was lower than stated here and obviously in this draft permit they did not include the information that was supplied to them during the hearing. There are more than three (3) units in the United States of America in attainment that are being permitted at considerably less than 2.5 PPMVD. Why then is our state, which already has one of the poor records for air quality permitting plants at average available technology, rather than the best available technology? In our opinion the power plant companies seems to put undo stress on the cost of controlling pollution. In the papers submitted, air quality issues as well as in other papers previously submitted to the DEQ, it is clearly shown that the cost of figures that the power plant company have given particularly with regard to selective catalytic reduction are incorrect. Papers recently submitted to the DEQ have shown that selective catalytic reduction is in the range of $1600 to $2300 a ton. Could the DEQ please show us, the citizens, from papers from a neutral source that the cost of not only selective catalytic reduction, but of SCONOx are as high as the power plant companies say they are in their permits, rather than the papers that we have submitted showing that they are lower?*

See Response to CN 4, above. Further, the BACT analysis is done on a case-by-case basis. Selective Catalytic Reduction (SCR) and SCONOX were eliminated as BACT in the initial permit for this facility because they were economically infeasible. SCR is now being added to this facility to satisfy BACT requirements. Therefore, the cost of SCR is no longer an issue. SCONOX (which is a new technology that has not been demonstrated for long-term commercial operation on large scale combined cycle plants) was eliminated as BACT for this facility due to the extremely high cost per emissions reduced. The lowest cost calculations for reduction of NOx were $26,000 per ton. The costs for SCONOX were independently verified by DEQ directly with the manufacturer/distributor.

14. *What efforts has the DEQ done to monitor the drift from the power plant given the waste water treatment facility was out of compliance. It is our understanding that not only does the DEQ not have a mobile unit for measuring a pollution levels, but that higher levels in the case of pesticide dumping could occur in the drift, and thus seriously harm human beings. Since the power plants supplies 100% pure water for their turbine blades, why is the DEQ not requiring them to supply 100% clean water so that the air that humans and other environmental creatures and plants won't be harmed?*

See Response to CN 11, above.

15. *In Dave Dimick's memorandum to Dawson Lasseter of January 5, 2001 according to a letter from EPA, as part of BACT analysis, the applicant must justify as why control could not be required due to economic impact. This justification must include documented capital operating costs, either with data supplied…Furthermore, the applicant must document the design parameters to independently verify claim costs. Finally, where initial control costs projections on part of the applicant appears excessive or unreasonable, more detailed in the conference of cost data are necessary. According to data from Savvy Systems Designs, Inc. – Research Division as noted from data supplied by the DEQ themselves, the health risks of exposure to ozone and particulate matter are high. The economic cost both directly for medical treatment and indirectly for work lost, time lost, life quality and other issues, we understand that the cost to the public will be higher than the cost of the power plant to install water purification facilities to clean then air of heavy metals, pesticides and other pollutants previously mentioned during the air hearing. Why is the DEQ not requiring the plant to clean up the water and therefore the air in this case, since the power plant is demonstrated that it has the technology and can do this? We see no data in the draft permit supporting their conclusion that this can't or shouldn't be done.*

See responses to CN 5, 11, and 13, above.

16. *In order to control the pesticides in the drift, we see no evidence that the plant has considered selection of a particular control system such as drilling a well and taking pure water, or cleaning up the water. It is noted that BACT must be justified in terms of the statutory BACT criteria and supported by the record and must adequately explain the basis for their rejection of other more stringent control operations. We have not seen this with regard to pesticides in the drift. We see no evidence that the power plant or the DEQ has shown that putting pesticides in the drift even in small amounts is healthful, economic, or is in the public interest. Would you please supply evidence that this is a good thing to do?*

See response to CN 11, above.

17. *In order to protect human health the power plant has the option of buying water from the Arcadia reservoir or from Oklahoma City. Why has it not exercised these options in the public good? It should be noted that the power plant companies have been illegally taking water from the deep fork this month, when it is our understanding that water for these uses, such as constructing their pipeline to the North Canadian waste water treatment plant, would be purchased from other sources and not take illegally. What precautions do you have in place that they will not take similar advantage of this draft permit if it is granted?*

This comment is beyond the scope of the permit modifications being reviewed. Selection of the source of the water to be used at the facility and allegations regarding illegal taking of water are issues beyond the permit review process. Also see response to CN 11, above.

18. *In Dimick's memo, January 5^{th}, it is noted that consultation by the review authority with EPA's implementation enters, particularly the CTC, is advised in determining whether toxic pollutants would be omitted in amounts efficient to be of concern. Has the DEQ done this with regard to heavy metals and pesticides in this case?*

See response to CN 11, above. See also the modeling results for these substances beginning on page 24 of the draft permit.

19. *Since the "Top Down" approach shifts the burden of proof to the applicant to justify why the proposed source is unable to apply the best available, we would ask the DEQ why it is that the applicant has not been required to show the costs to the public in terms of the paper that we have supplied you on particulate air pollution for children, we have also supplied information as far as health risks of exposure to ozone and particulate matter of concern, and the cost of premature death, morbidity and mortality are considerable. This has to be weighed against the cost of pollution control, as far as we are aware, the power plant company has submitted no statistics whatsoever to show the cost to the public. It is my understanding that as of yet the DEQ has not supplied to Savvy Systems, Inc. – Research Division the requested information so that this vital information can be calculated. It is my understanding that this was requested and it is crucial for this draft permit. I would ask that the DEQ not issue this permit until either the power plant company supplies this data or the Savvy Systems Design Inc. supplies this data, so that it can be brought out in the public interest to see how much pollution control is necessary. According to Demick's memo on page 10, "a regulatory agency should fully develop and resolve any technical issues raised during the comment period during the drafting and review of the permit, failure to document the basis for it's decision making process in the Administrative record is considered an error in BACT analysis." We would therefore ask the DEQ to document the technical issues raised in the previous hearing and document the basis for their decision making process. Why has this not been done?*

See responses to CN 4, 5, and 13, above regarding evaluation of the permit modifications being reviewed.

20. *In the Interrogatories during the air hearing, Dr. Dawson has asked several times through the Interrogatories for information about these solvents as asked for information including the amounts and exact types of solvents, which will be used in the cooling tower. The Administrative law judge did not make the power plant company answer those specific questions. This is a matter in the public interest and should be in the public record, why has the DEQ not supplied this information?*

All emissions from the cooling towers were evaluated and are listed in the draft permit or in these responses. DEQ is not aware that there are any solvents proposed for use in the cooling towers.

21. *In the paper herein submitted "Air Quality Issues", SCONOx is clearly shown to be possible. I quote from Demick's memo, "Absence and explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source, the review authority may presume it is technically feasible." That paper has shown the cost effectiveness is considerably less than $2600 a ton, as stated by the power plant companies draft for the Arcadia permit on page 7, but also not taking into account was the cost to the public which Savvy Systems Design, Inc is working on. We would ask the DEQ to take this new information into account and if this is not feasible, we would ask why not? Demick's memo clearly states "unless it is demonstrated to the satisfaction to the permit issuer that such unusual circumstances exist, then the permit applicant must use the most effective technology." (see page 11 – Demick's memo, and page 6 and 7 in the draft permit for the Arcadia plant.)*

See response to CN 13, above. See also the BACT analysis in the Section IV(A) of the permit modifications being reviewed (2000-090-C(M-1)(PSD)). It should also be noted that SCONOX has never been determined to define BACT for facilities of this size in any state in the United States.

22. *According to Demick's memo "the standard for each source category" shall require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, were achievable)…that the administrator determines is achievable." In view of this, why is it that the power plant company can't buy clean water from either Edmond or Oklahoma City, as it certainly possible for them to do and thus not contaminate the air? It seems to me reading Demick's memo that this would be required in the interest of public health.*

See response to CN 11 and 17, above.

23. *According to the paper "Air Quality Issues". Cancer impacts from the turbines are significant at the Morro Bay plant. Why is it that cancer and non cancer health impacts from the turbines are not looked into as the authors of the paper "Air Quality Issues" have done with respect to Morro Bay?*

See response to CN 5, above.

24. *Demick's memo on page 21 mentions extremely expensive cost effectiveness of least stringent controls in terms of millions of dollars per cancer case avoided. Why is it that the DEQ is not requiring the power plants to spend a fraction of this money on pollution control, which like second hand smoke from cigarettes has shown to be extremely harmful in causing many more cases than the section 112 pollutants referred to in this article. Since OAC 252:100-41-2, defines best available control technology that is available for each contaminate…taking into account energy, environmental health risks costs and economic impacts of alternative control systems, why do we not see the health risks evaluated in the draft permit, as well as a comprehensive evaluation as far as the economics are concerned to the people that get sick with the increase of pollutants? The New Source Review manual states how source testing is to be performed.*

See response to CN 5 and 11, above.

25. *There are seven (7) items that are listed on page 69 of "Air Quality Issues" which was given to you. These include that conditions must specify when and what tests should be performed; under what conditions tests should be performed; the frequency of testing; the responsibility of performing the test; that the source be constructed to accommodate such testing; the procedures for establishing exact testing protocol; and the requirements for regulatory personnel to witness the testing should be carried out. We do not see in the draft permit that has been submitted how these apply to start up, shut down, 50% load, duct burners on or off, or steam injection for power augmentation. This information should be subject to public review. Therefore, why are continuous emissions monitors not being used to comply with the limits for the pollutants being put out by the power plant, but particularly SO_2 and PM_{10}. Why is the DEQ not requiring the sulfur content test on a monthly basis, because of sulfur content being quite variable with common spikes?*

See Specific Conditions Numbers 6, 7, 8, 9, 10, 11, 12, 14, 15, and 16 in the permit. These requirements are far more stringent than the comment requests.

26. *Because of the variation in pollution and the difference start up times for the gas turbines, why is the DEQ not requiring the start up criteria required for Morro Bay permit under C, page 70? Since this seems like a reasonable control and condition requirement, why is the DEQ not requiring it?*

The cited page 70 is a suggestion for the Morro Bay permit, NOT a requirement. See Response to CN 7, above.

27. *Since it is required by the state and monitoring and enforcement provisions are required by the government, why is there not a monitoring and enforcement provision for the terms in previous questions, and for simultaneous turbine start up?*

See response to CN 7, above.

28. *Is it not wise to keep a real time log of unit output showing unit output for each turbine intervals of no more than ten (10) minutes, since this is required in some power plants in the rest of the United States?*

It is not clear what is meant by "unit" output. It could be wattage output or pollutant output. See Specific Conditions 10, 11, and 15 which outline continuous emissions monitoring requirements.

29. *Since PPM2.5 is so dangerous, why is the DEQ not requiring a monitoring station directly north of this power plant in the zone of maximum pollution?*

Siting of monitor locations must follow very detailed guidelines set forth by EPA. There are currently no regulations that require an individual facility to conduct $PM_{2.5}$ monitoring. Also see Response to CN 222, below.

30. *Because of the extreme pollution in Oklahoma City, why is the DEQ not requiring the applicant to agree to a reassessment of BACT in three (3) years, at which time it must make whatever equipment changes are necessary to meet the then BACT standards?*

It is not clear to what "extreme pollution" the comment refers. Oklahoma City is in attainment for all criteria pollutant standards. The draft permit contains BACT that meets all applicable legal requirements. The permit also contains enforceable emissions limitations with which the facility must comply. For these reasons, future re-evaluation of the BACT as proposed by this comment is inappropriate.

31. *Why is the DEQ not addressing accumulative emissions on a calendar quarterly basis within the cumulative annual totals, since this was done at the Moss Landing power plant in California and represents state of the art? (Please see page 72 in the paper "Air Quality Issues" under F-quarterly emissions limits).*

The permit for this facility establishes consistent hourly limits as well as yearly limits which are more stringent than quarterly limits referenced in this comment.

32. *Since formaldehyde, acetaldehyde, benzene, specified PAH's and acrolein are so toxic why are these not being calculated and recorded on an annual basis as far as the maximum projected emissions are concerned?*

See page 24 of the memorandum for the calculated maximum emissions of the toxics referred to by the comment.

33. *Why has the DEQ not considered the appropriateness of a temperature limitation for ammonia injection for this project?*

Specific Condition Number 1 establishes the emission limitation on ammonia. Temperature limitation is not necessary.

34. *Why is the condition for "the HRSG duct burners shall not be fired unless it's associated gas turbine is in operation?" (in the permit?)*

The HRSG duct burners for each turbine can't be fired without the turbines because they run on the turbine exhaust.

35. *Why is not the condition that all records be made available to the DEQ personnel upon request?*

It is not clear what information the commenter is seeking with this comment. See Standard Condition Section III (A) (June 1, 2001).

36. *Why is not the condition "each gas turbine and related HRSG shall be abated by the properly operated and properly maintained SCR system whenever fuel is combusted at those sources and the catalyst bed has reached operating temperature"?(see page 74 pp5 of "Air Quality Issues")*

It is not clear what information is being sought with this comment. See Specific Condition Number 5 that requires properly operated SCR.

37. *Does the DEQ have requirements of reporting a breakdown that are reasonable such as within one (1) hour of their detection and requiring a specified report not later than five (5) days after the breakdown. Since this was required in California at Moss Landing, why should it not be required here in Oklahoma?*

See Standard Condition Section II.

38. *Are there any requirements to notify the DEQ of any violation of the permit conditions, not just those resulting from breakdowns. I feel this condition should also specify how the notification is to be made and when. It is clearly very important to know immediately if the permit conditions are exceeded even when there is no breakdown. Why is this not being done by DEQ.*

See Standard Condition Section II.

39. *Why is a "continuous monitoring systems must be operated to monitor and record mole ratio of injected ammonia to exhaust stack NOx. This system must be accurate to within 5%." Since this is a condition at the Moss Landing power plant in California, why is this not a condition of this similar power plant?*

See Specific Condition numbers 5 and 11, below.

40. *In the draft permit on page 5 under A: Best available control technology, why is XONON not included in the analysis? This is a well known technology which is technically feasible and it's used lower emissions rates than those proposed for the Arcadia plant. The DEQ has failed to identify BACT by failing to perform an analysis, which includes XONON.*

XONON has not been determined to meet BACT in any state in the U.S. for a facility of this size.

41. *Under NOx BACT review. On page 5 of the draft permit, we believe that the author's of the draft permit are in error when they say that 3.5 PPMVD corrected to 15% oxygen for turbines will fulfill the BACT requirement. The level of control that is satisfactory and necessary is outlined in the paper "Air Quality Issues", and we would suggest that the DEQ very carefully read this entire document and then answer the question why should the levels of the criteria pollutants not be established as noted in this paper because clearly they have been established in many other locations which are known to the DEQ and some of which are added in the paper, others have been added by our hearing. We feel that the arguments in this paper are far superior to those given in the Arcadia's draft permit, and would ask the DEQ to answer in view of all the arguments in the paper, why that the standards in "Air Quality Issues" are not being adopted?*

See Response to CN 4, above.

42. *On page 6 of the draft permit, a discussion is made why SCONOx is considered ruled out as a control option. Ruling it out by the Arcadia limited partnership was only two (2) paragraphs, I would draw attention to the paper "Air Quality Issues" which under part 4, BACT has not been required for NOx, on page 11 has an extensive discussion of SCONOx and to some extent XONON because this is a similar process. This is discussed through page 52 very thoroughly showing that not only is SCONOx technically feasible, has been installed and successfully operated, is available; is applicable, has not been determined to be technically infeasible, can be scaled up, that the dampers are reliable; that the control system is reliable, that the catalyst regeneration will not cause an explosion hazard, that SCONOx does not increase back pressure, that SCONOx steam consumption is minor, that there are commercial warranties, that financing can be accomplished, that SCONOx is cost effective, that SCONOx eliminates ammonia impacts, that ammonia impacts must be considered with PM_{10} emissions, that PM_{10} formulation contributes to existing violations at state standards, that PM_{10} formation contributes to existing violations at state standards, that PM_{10} formation causes SCR maintenance problems, the PM_{10} formation causes visibility reduction, and that PM_{10} formation endangers endemic biota. For these reasons we would like the DEQ to explain why it is that this is not the procedure of choice? It is very clear that SCONOx achieves 0.7 PPM of CO and according to the calculations in this paper is clearly cost effective.*

Since SCONOX is not operating in any plant of this size anywhere in the U.S., it is not clear that it achieves the rates cited by the comment. SCONOX is not BACT in any state in the U.S.

43. *In the paper "Air Quality Issues" it is clear that the source tests support a CO limit of less than 1 PPM (see page 45 or Air Quality Issues and other material therein on carbon monoxide). The question is in view of this data, why is the DEQ allowing Redbud limited partnership to have an outrageously high 17 PPM of CO when this can be easily controlled down to .5 PPM as shown on page 47 of Air Quality Issues?*

See response to CN 4, above.

44. *In view of the other Air Quality benefit of CO control found on page 53 through 56, why is it that since volatile organic hydrocarbons are so dangerous and that carbon monoxide control is so cost effective as represented on other power plants, why is that not being enforced?*

It is unclear what information the commenter is seeking with this comment. However, see response to CN 4 and 13, above and the BACT analyses for CO and VOC's found in the permit memorandum on pages 9 and 10.

45. *Once you have read the paper "Effects of Particulate Air Pollution on Children", plus consideration of the references Dr. Dawson has submitted for the air hearing and which were not considered for reasons listed by the administrative law judge, how can the DEQ, whose main job is to protect the health of the citizens of Oklahoma, possibly not consider these gargantuan health and economic effects of the tremendous amount of pollution including particulate matter that this power plant is omitting when it can be so easily controlled with SCONOx, or at least with adequate levels down to PPM as listed under Air Quality Issues combined with catalytic oxidation for CO?*

See responses to CN 4, 5 and 13, above.

46. *On page 8 of the draft air permit, I believe that the people that wrote the permit are in error. It is very clear from paper "Air Quality Issues" that combustion turbines equipped with dry low-NOx combustion and duct burners can be controlled to far below the ranges of 3 to 5 PPM VD, using SCR technology.*

The DEQ permit writer correctly stated on page 7 of the draft permit as follows: "NOx emissions from combustion turbines equipped with DLN combustion and duct burners can be controlled to around 3-5 ppmvd using SCR technology."

47. *The second paragraph on page 8 of the draft permit clearly indicates that SCONOx is the method of choice for pollution control. What would be the DEQ's criticism of this assessment given the facts in the paper "Air Quality Issues"?*

See response to CN 13 and 42, above.

48. *Page 9 of the draft air permit no comparison is made between dry low-NOx and selective catalytic reduction and SCONOx. This comparison is made "Air Quality Issues". What is your criticism of the comments made in "Air Quality Issues"?*

This comment is beyond the scope of the permit modifications being reviewed. It would be neither appropriate nor relevant for DEQ to criticize comments made on a permit at issue in another state. Discussion on page 9 of the draft permit is the BACT analysis for CO on the intermittently operated auxiliary boiler, emergency diesel generators and diesel-powered fire pump. The analysis correctly determines that the cost of add-on controls for the intermittent units is cost-prohibitive. However, the analysis does require engine design and good operating practices as BACT for the auxiliary boiler and engine design as BACT for the emergency diesel generators and diesel-powered fire pump. In the permit, each of these units has federally enforceable limits for CO emissions.

49. *On page 9 of the draft permit, the CO emission rate under maximum low conditions will be limited to 17.2 PPM VD for the combustion turbine firing natural gas. The writer of the draft permit clearly ignores all the power plants that are permitted with much lower levels of CO. CO are clearly poisons, the impacts are given in the references not only in the "Air Quality Issues" but also from all the references submitted for the air hearing by Dr. Dawson. To say that there are "no adverse economic, environmental or energy impacts associated with the proposed control alternative are just no so. The cost estimates on the draft on page 10 are calculated by the same people that said costs for removal for a ton of NOx was $12,000.00 and had the administrative law judge believe it. Papers have been submitted to the DEQ which shows clearly that this is not true. Whether design and good operating practices do not lower carbon monoxide. CO is a poison which has the characteristics have previously been listed in the references for the air hearing, and the information currently submitted from "Air Quality Issues", clearly shows that 17.2 PPM VD is not BACT to CO. In their calculations as listed in the original permit are clearly flawed as has been previously brought out. Why would the DEQ even accept this as reasonable given current data at their disposal?*

See responses to CN 4 and 13, above.

50. *On page 10 of the draft permit, under SO2 BACT review, for reasons mentioned previously a monitoring system done at frequent intervals because of spikes in sulfur content is entirely necessary. Why is not the DEQ as required, putting this in a permit requirement?*

See response to CN 29, above.

51. *It is noted on page 2 of the permit that the auxiliary boiler will increase from 20 MMBTUH to 93 MMBTUH. Could you please explain why it is this change was made and what impact this might have considering that 3000 hours are wanted for this use?*

The addition of the SCR prompts the need for a larger auxiliary boiler. The operating hours are the same as currently permitted. The change in emissions is small, the effect is insignificant.

52. *On page 11 of the draft permit, we disagree that an oxidation catalyst was shown not to be cost effective for control of VOC. Oxidation catalyst can control both CO and VOC emissions reducing the annualized costs of the oxidation catalyst system far below that listed in this draft permit. When the system is used combining a reduction of VOCs in CO, it becomes cost effective at a reasonable cost per ton as noted in the preceding hearing and in "Air Quality Issues". Why is catalytic oxidation not required by the DEQ? In a review of Clearing house and turbine data shows that catalytic oxidation is BACT for CO and VOC removal. This is further exemplified by Dimick's memo of January 5, 2001.*

See response to CN 11 in permit number 2000-090-C(PSD); as well as responses to CN 4 above. An oxidation catalyst would not be economically feasible as BACT for the turbines at the facility even if the expected reductions in CO (256.2 tpy) and VOC's (28.4 tpy) and NOx (284.6 tpy) were combined for the cost analysis. The cost of removal would still be approximately $63,773 per ton removed.

53. *On page 12 of the draft permit, under PM10 BACT review, it is absolutely false to say that there are not environmental impacts with their proposed control alternative, which is to do nothing about the particulate matter PM10. In this case named "pesticides" from the previous air quality permit hearing, which include diazonon, chlordane and heptachlor, as well as their breakdown and combination products are a serious issue. They purposely in this permit do not include PPM 2.5 or discuss whatsoever in the entire permit the ill effects of the pesticides or heavy metals in the drift itself, and particularly if it combines with the particulate matter from the stack getting down into peoples lungs and hurting them. Please read the paper "Effects of Articulate Air Pollution on Children: Potential Impacts of the Proposed New Morro Bay Power Plant." That power plant is substantially similar to the Arcadia limited power plants project and therefore details that are mentioned are applicable to the Arcadia plant. SCONOx is the best alternative to clean up the particles from the stacks, and using pure water or clean water is the best alternative to eliminate the heavy metals and pesticides from the drift. Both of these are possible, as noted in "Air Quality Issues", and because they certainly can clean up the water for their turbines, they also can clean it up for their cooling towers. Drift eliminators will not reduced the particulate matter in the air sufficiently to protect the public against the pesticides in the water. In view of these facts then, why is the DEQ not requiring SCONOx or at lease selective catalytic reduction at a reasonable level as mentioned in "Air Quality Issues", combined with catalytic oxidation for CO and VOCs, so that the level of all these things will be reduced to protect public health and safety?*

See responses to CN 5, 11, 13, 42 and 52, above.

54. *Why isn't the DEQ requiring pure water since the power plant makes pure water for its turbines. In any event, to totally clean up the water from pesticides and heavy metals?*

See response to CN 11, above.

55. *On page 19 under stack parameters, it is noted that the stack diameter increased from 17 to 18 feet from the prior permit, and the stack velocity increased from approximately 17 feet per second to 60.9 feet per second. Could you explain why there is such a tremendous increase in stack velocity when the stack diameter increased, which ordinarily would slow the stack velocity?*

A comparison between the original permit (issued on August 16, 2001) and this draft permit (M-1) reveals that stack diameters for turbines numbers 1 through 4 were increased from 17 to 18 feet. However, examination of the stack velocity indicates a decrease from 70.2 feet/sec in the original permit to 60.9 feet/sec in the M-1 permit.

56. *It says page 17 of the draft permit, paragraph 5 that the data was obtained in the USGS special data transfer standards and converted. Why is that more recent and therefore we believe more appropriate yearly data for the meteorological data used could not be translated and effectively used?*

This issue is beyond the scope of the permit modifications being reviewed. There has been no change in the availability of meteorological data nor in the meteorological data used in the modeling. Further, the issue of whether the most recent readily available meteorological data was used has been fully litigated. In the previous litigation DEQ demonstrated that the meteorological data used was the most recent readily available.

57. *On page 19 of the draft permit under Emission Rates Modeled, the PM_{10} in pound per hour for turbines 1 through 4 seem absolutely excessive and according to "Air Quality Issues" does not at all represent BACT for PM_{10}. Could you explain why that you would allow this to become BACT when it is so high?*

See response to CN 5, above and the discussion of PM_{10} BACT on pages 11 and 12 of the draft permit memorandum.

58. *The CO and PM_{10} is excessively according to "Air Quality Issues". Why would you allow turbines 1 through 4 to put out this much CO_2 per hour when reasonable control methods can be implemented?*

There is no CO_2 listed in the draft permit. See response to CN 5 and 49, above; as well as the discussion of PM_{10} BACT on page 12 of the draft permit memorandum.

59. *In the table in the draft permit on page 20 under Maximum Concentrations in Micrograms per Meter Cubed, the PM10 24 hour is listed in 1986 4.35 when the significance level is 5. Don't you feel that if one looks at other years both before and after 1986, that this level is not representative and that particulate matter represents an extreme problem as demonstrated in the paper "The Effects of Particulate Air Pollution on Children"?*

The comment is incorrect in its assumptions. The meteorological data is representative data. The concentration data represents maximum concentrations.

60. Please explain on page 20 of the draft permit the calculations that were made for saying "the impact of all proposed VOC and NOx emissions associated with the project is estimated at .0166 PPM?

The method in "VOC/NOx Point Source Screening Tables" was used to calculate (from the results of reactive plume modeling of the emissions of volatile organic compounds (VOC) and NOx) the ozone impact of all proposed VOC and NOx emissions associated with this project. That result is 0.0166 ppm.

61. We believe that if the calculations were done in a different fashion including start up and shut down time and stoppage of turbines of the projected emissions will exceed the ozone in AAAS of 0.12 PPM, as noted in the paper "Air Quality Issues". Please revise calculations to show the impact as noted in the paper "Air Quality Issues". In the draft permit on page 20, last paragraph on the bottom continuing through the upper half of page 21, the applicant relies on the ozone impact study conducted Environ March 20, 2000. We have pointed out in the past the serious deficiencies associated with this study. It is only 2001, and the ozone standard is already being breached in the Tulsa/Oklahoma City area. Not only that the study did not make any sort of reasonable estimations as to contributions from the various sources of air pollution. It is very clear that automobiles and power plants rank in the upper eschalon of polluting sources. Assumptions were made in these studies that may not come true. For example, if new emissions controls on trucks are not placed, then since we have already broken through the 1 hour standard in the Tulsa/Oklahoma City area, it is obvious that be the year 2007 with the addition of more power plants that the saying these sorts of things like they are "estimated at no measurable effect on the peak 8 hour ozone concentration in the Tulsa/Oklahoma City area" is obviously false. Why is the DEQ allowing this sort of statement to be made and believing it?

The calculations were correctly made. Further, DEQ cannot revise its calculations in accordance with public comments made on a permit at issue in another state. The referenced document, "Air Quality Issues" is not an approved document for use in evaluating New Source Review applications. Actual studies and actual modeling exercises are conducted because the correct answers are often not obvious even to the trained expert. Environ International Corporation is an internationally known and respected firm located in Novato, California.

62. How can the DEQ possibly monitor this power plant appropriately without preconstruction or post construction ambient monitoring in view of the increase in size of the power plant?

Page 18 of the draft permit memorandum explains ambient monitoring requirements. Recordkeeping and reporting requirements are described in the Specific Conditions 6, 7, 8, 9, 12, 13, 14 & 16 of the draft permit.

63. *Why would the DEQ possibly allow existing national air monitoring system monitoring site located at 8.4 kilometers south, and 22.2 west of the facility when the facility has been modeled to have the maximum concentration of the VOC north of the facility? We believe that the DEQ should require that the power plant operate and pay for a monitoring site. Why is the DEQ not doing this? The power plant might solve this problem by bringing down the VOC with catalytic oxidation, why is the DEQ not requiring this?*

See response to CN 29, above and 222, below.

64. *On page 22, question 65 of the draft air permit, why is the DEQ not requiring the maximum ozone monitoring data summary from the monitor which gives the maximum in the area 10th and Stonewall for NOx rather than this hand selected and hand dated monitoring from the people who originated this permit?*

There is no question 65 on page 22 of the draft permit. However, page 18 of the permit requires use of data from the existing (NAMS) National Air Monitoring System Site no. 401091037-1. The data from this site provided a conservative representation of the most accurate air quality at the location of this site.

65. *On page 22 of the draft permit on soils and vegetation, according to the ozone study put out by the EPA in 1996 and referred to in the air hearing is estimated that plant and crop destruction for given crops as submitted to the DEQ may result in losses to approximately 3%. This is not in accordance with the statement that "no significant adverse impact on soil and vegetation is anticipated due to the proposed power plant". Would the DEQ please review the position paper of the EPA on ozone, and explain why it is that the power plant is going to be allowed to have an adverse effect on crops, particularly since they have to apply for an acid rain permit when this could be avoided with proper pollution controls?*

Discussion of the impact on soils and vegetations in the permit memorandum is on pages 19 and 20. The modeling conducted which demonstrated compliance with the primary NAAQS simultaneously demonstrated compliance with the secondary NAAQS which protect public welfare and inter alia agricultural soil. The secondary NAAQS are higher than or equal to the primary NAAQS. Further, EPA strongly encourages the use of SCR to control NO_x emissions from gas-fired turbines used to generate electrical power. The commenter previously used this information to support his arguments that SCR should be selected as BACT for the facility.

66. *On page 23 of the draft permit under visibility impairment, why are the conditions that were imposed upon the Moss Landing plant with regard to watching visibility impacts not required for this plant? (See paper on "Air Quality Issues") If one included start ups and shut downs as noted in "Air Quality Issues", then the amounts of the extremely toxic substance Acrolein noted on page 27 of the draft permit in tons per year, will it exceed point .60? On page 24 of the draft permit it says that OAC 252:100-8 permit for parts 70 sources show that this is more than an "insignificant activity", especially in view of the human health hazards as noted in "Air Quality Issues" in the chapter on Acrolein. Why then is the DEQ not requiring catalytic oxidation or other methods to bring this hazardous air pollutant down to more reasonable levels?*

DEQ cannot revise the permit at issue here in accordance with public comments made on a permit at issue in another state. Also see response to CN 7 and 11, above.

67. *I don't understand on page 27 and 28 that include tables on toxic air pollutants from the cooling water towers, why is it that the pesticides diazinon, heptachlor, chlordane and their toxics by-products are not added since the power plant people admitted themselves in testimony that these substances were present in the waste water from the north Canadian waste water treatment facility and therefore would be present in the air from the cooling water towers?*

See response to CN 11, above.

68. *Why is it that the DEQ in spite of being asked has made no legal determination as to whether or not the plant has made an illegal use of pesticides by putting them up in the air in the form of the drift and thus harming plants, environment, animals, and people?*

See response to CN 11, above and 69, below.

69. *The DEQ was asked for a determination as to whether or not it was legal for the City of Oklahoma City to sell pesticides in the water, and whether it was legal to put them up in the air. The Rodent Insecticide Act, as mentioned in the air hearings on this plant prohibits this. We do not have a legal opinion from the DEQ to counter this prohibition, could you please explain on these pages why that has not been done, and could you please get us an opinion?*

This comment is beyond the scope of the permit modifications being reviewed. Legal opinions about what Oklahoma City can or cannot do are not the subject of this permit. Further, DEQ demonstrated during the proceeding on the original permit for this facility that the referenced Act does not apply to PSD permits such as the one at issue here.

70. *On page 28, of the draft shows that cancer causing substances are being omitted into the air as noted in the permit. Why is the DEQ not taking steps as noted in "Air Quality Issues" in the section under cancer and other sections, to limit the impact of these toxic substances?*

See Responses to CN 5 and 11, above. Further, pages 24 and 25 of the draft permit also show that all toxics will be emitted below the respective Maximum Ambient Air Concentration (MAAC) as required by Oklahoma state regulations.

71. *On page 28 of the draft permit it says "the modeling for ammonian and sulfuric acid released from combustion units were based on data corresponding to facility operations at 1220 mega watts". Does this mean that all the other substances were just taken from the old permit and used not remodeled because of the increase in change in turbines? If this is so, why isn't the DEQ making them do complete modeling?*

The results of the original modeling for the substances mentioned were so far below de minimis levels that a nominal increase in emissions would not have raised the concentrations above the respective MAACs.

72. *Since the turbines are different, could the DEQ please point out where on what page on the draft permit is listed the exact maker, type, model and number of both the turbines and after burners? On the original permit a GE7A frame turbine was noted, please point out those details to us. Since the turbines vary it is noted in the paper "Air Quality Issues", dies this mean that the DEQ has not checked any of this information? On page 27 of the draft permit under NESHAP 40 CFR Part 63 we believe that this is applicable at this time because the turbines will not be installed by May of 2002. Also in subpart B, case by case marked it applicable because the facility has noted in tons per year formaldehyde is over the de minimis levels and can cause cancer. The duct burners as mentioned will only add to these problems. Could you please explain the EPA's May 25, 2000 interpretative ruling on this issue or provide this in the answer?*

1) The draft permit will be changed to show maker, model number and type of turbines and duct burners.
2) The regulations cited on page 27 under NESHAP 40CFR Part 63 are not scheduled for promulgation until May 2002. DEQ cannot apply law that is not yet in effect. It should be noted that DEQ specifically reserved the right to reopen the permit if any of the referenced standards become applicable.
3) See response to CN 11, above.

73. *Under page27 on the draft permit, under Tier classification in public review, it is apparent that the permit is totally changed, increasing the megawattage of the power plant and making all kinds of changes in stack diameter, stack height and amounts of pollutants therefore everything in this permit, in our opinion, is subject to public review. Does the DEQ deny this and if so, what is not subject to public review?(As far as Tier 3)*

See response to CN 1, above.

74. *On page 32 of the draft permit, in paragraph 2 they state "the affidavit certifies that the applicant has option to purchase the land". Since in my* opinion the power plant is deemed built illegally at the present time without a construction permit and without an air permit *that they should state in fact if they have taken the option and purchased the land. The citizens wonder why since the plant does not have a valid permit, and according to the Clean Air Act it is illegal to begin construction on a power plant before they have a permit, why is the DEQ acting as an enabler for the power plant to break the law? Why has the DEQ not contacted both the state fire Marshall and the county so that they can have an injunction on the power plant to stop building until such a time as they do acquire a valid air permit?*

See response to CN 10, above.

75. *In the draft permit, page 32 we would disagree with the fact that the power plant company says "ambient air quality standard are not threatened at this site". In view of the previous questions and of the paper submitted including "Air Quality Issues" and "The Effects of Air Pollution on Children" as well as all the material submitted during the previous hearing, including all the references we would hold that the plant must comply with BACT for the issues that we have brought up or else not build the plant. At the current time there is a major issue which has not been resolved, and that is that of pesticides that are being put up in the air which is completely contrary to public health and safety. These issues have to be resolved before any construction should be done. Therefore I request that the DEQ help with an injunction against the power plant to stop construction until this is solved either at the DEQ level or at a court level. This is sufficient for the DEQ to take action, otherwise I believe they are an accessory to a crime. That crime is not of obeying the provisions of the Clean Air Act, which mandate that a valid air permit be issued before any construction can be started. If this is not right, please quote the statutes so that you will correct my understanding on the matter? Under Specific Conditions in the draft permit, page 1 through page 5, we would expect that BACT would have many more specific conditions such as the Moss Landing power plant in California and the comments that were previously in the questions regarding this specific condition, we would ask the DEQ to change and modify this permit so that current conditions as used, for example by the Moss Landing plant are implemented for the protection and safety of the public. In addition to the continuous monitoring on NOx, we also suggest that monitoring on the other pollutants especially ammonia, carbon monoxide and sulfur dioxide be made part of the specific conditions for this permit. We would also ask that penalties be provided if the power plant company cannot maintain and accomplish these objectives. On page 4 in condition 13 of the draft permit, a better schedule for start up and shut down and maintenance is mentioned in "Air Quality Issues" under their comments on this subject. Why cannot these be carried out?*

This is a compilation of several comments that have been previously addressed in this document. See responses to CN 1, 7, 11, 25, 31, 42, 48 and 52, above.

76. *On page 6 of Title 5 of the Title 5 permit standard conditions, it states under section 12 B-2 that is the permit contains a material mistake or that the permit must be revised or revoked to insure compliance with applicable requirements. Is it not a requirement that modeling must be complete and specific to the turbines which are employed as part of this permit?*

All required and applicable modeling was conducted for the evaluation and preparation of the draft permit.

77. *In response to comments on permit number 2000-090-C(PSD) dated December 17, 2001, the DEQ admits that recent permits have required as low as 2.0 ppmvd. Since the Oklahoma City metropolitan are in near none attainment and several other power plants (Edmond, Newcastle) have been permitted with just "good combustion practices and design" and given that the Oklahoma City has receive an "F" from the American Lung Association with regard to air quality, why in the world is not the DEQ requiring the limits that seem reasonable at 2.0 ppmvd thus requiring catalytic oxidation for CO, especially when you consider that the job of the DEQ is to protect the public rather than to save money for the power plants?*

See responses to CN 4, 5 and 13, above.

78. *From question 15 and response to comments memorandum dated September 27, 2000, since the first question period it has become obvious that air cooling towers not only save water but are state of the art in represent BACT. Why are you not requiring air cooling towers and how will they effect the amount of pesticides coming out of the drift if one tenth (1/10) as much water is used and therefore one tenth (1/10) the amount of pesticides in the water?*

The water cooling towers selected by the applicant meet the applicable air emissions standards. Further, selection of process equipment at the plant is within the discretion of the permit applicant and there has been no change in the type of cooling tower proposed for this facility since the original permit was issued. Therefore, this comment is beyond the scope of the permit modifications being reviewed.

79. *Question 15 responses to comments on the draft permit dated December 27, 2000. Why has the DEQ continued to not release public information regarding the solvents and other chemicals and their amounts used in the cooling towers by the power plant company?*

See response to CN 20, above. Nothing has been withheld from any member of the public.

80. *Since chromium is considered heaxavalent and this of course caused tremendous problems for PG&E in California to the tine of $330,000,000.00 for causing cancer in humans, why is the DEQ not allowing this public information to be given to Dr. Dawson and others, particularly when the comment on question 15 under D says that the small particles in the vapor plume may contain chromium? Would the DEQ please explain how the six chemicals that are listed in the first rendition of the water permit are used to make better heat exchange in the cooling towers and how and where they are added and how they might affect public health? Also amounts per 24 hrs.*

The modification at issue here is an air permit. Water permit questions should be addressed to the Water Quality Division. Response to CN 15 in permit 2000-090-C(PSD) is included with the permit and is a matter of public record. Further, all substances alleged to be in the water were evaluated and determined to be at levels that are less than the de minimis level; see response to CN 11, above.

81. *From question number 16 comments year December 27, 2000. It is noted that in the answer "that the aggregation specific heavy metals with other particulate matter was not addressed in the modeling that." Particle size distributions are available on the World Health Organizations internet site, so were not deposition and depletion calculations carried out in view of the serious potential danger to public health?*

The response to question 16 cited above continues beyond the cited quote and goes on to state as follows: "However, as is discussed in response to CN 81, because in deposition and depletion calculations the mass of the pollutant is removed from the plume, the exclusion of deposition and depletion calculations represents the most conservative estimate of the ambient concentrations of these pollutants." If the study had done what the comment requests, the ambient concentrations of these pollutants would be calculated at lower levels than presented in the draft permit and their calculated effect on the environment would appear to be smaller than that presented in the draft permit.

82. *Question 17 under comments. When new data comes up to show that the six principle pollutants are a menace to public health, and the Scientific Advisor Board of the EPA has mandated this in new 8 hour standards, does not the DEQ have the responsibility to the public (since that is their main job) to protect them (see Effects of Particulate Air Pollution on Children and other medical data submitted by Dr. Dawson) even though the Supreme Court asked EPA for further modification. It clearly did not over turn what the Scientific Advisory Board has said, so is the DEQ not negligent if they do not make an effort to at least fashion the permit for this power plant company to correlate with health standards of the Scientific Advisory Board, which the Supreme Court did not over turn?*

All relevant and appropriate Air Quality rules and regulations have been addressed by the draft permit. See response to CN 5, above.

83. *In view of the significance for public health, why has the DEQ not required the power plant company to go out and measure the air at the site for specific levels of all criteria pollutants and other pollutants which might be in the air at the time, so that a base line can be established? This would be extremely important in determining what effect this huge power plant was having on the surrounding environment and community? This is especially important since the "monitor selected" contrary to the belief of the DEQ is not representative of the area being located at a considerable distance from the power plant and the exact wrong direction as far as the wind conditions are concerned, as shown by the applicant's own modeling. 22 kilometers west of the proposed facility seems to be outside of the modeling square grid, which is 20 kilometers square. Therefore we believe that the concentrations from the entire Oklahoma City area, specifically the monitoring station at 10th and Stonewall, should be used as the pollution tends to spread out over the Oklahoma City area. Why was this not done?*

See responses to CN 29, 220 and 222.

84. *In response to comments December 27, 2000, number 25. Since the level of toxicity is defined in OAC 252:100-41 is based on the most restrictive 8 hour time waited average concentration specified for work room air. Which of the listed indices were chosen and why? Was the most restrictive indices chosen?*

As the response to CN 25 in permit number 2000-090-C(PSD) says, the most restrictive of the indices in each case is used.

85. *For the hazardous materials as listed in the permit modification and in the original permit, do the MAAC levels of 1/10, 1/50th or 1/100th of the occupation exposure limit correlate to the classes A, B, and C of toxicity?*

Yes, the correlation is: 1/10 = C, 1/50 = B, 1/100 = A.

86. *Because of the dispersion parameters cannot handle zero (0) flow, a wind speed of 1 meter per second is used within the model for statement conditions (from December 27, 2000, question 44). How many days during the for each year that the modeling is being used for were wind conditions under a wind speed of 1 meter per second (i.e., 0 flow)?*

Actual meteorological conditions for central Oklahoma were evaluated in the modeling. Because the dispersion parameters cannot handle zero flow, a wind speed of 1 meter per second is used within the model for stagnant conditions. However, if an area has truly stagnant conditions, there is no pollution entering the area.

The ISC3 model accepts hourly meteorological data records to define the conditions for plume rise, transport, and diffusion. The model estimates the concentration value for each source and receptor combination for each hour of input meteorology, and calculates user-selected short-term averages. As part of the regulatory default options selected in the model, concentrations for calm periods are not included in the calculated averages. A statement at the end of the modeling output file identifies the number of hours that were identified as calm. For the five year period, 1986 reported the most calm hours at 226 or the equivalent of 9.4 days. The maximum NO_2 concentration occurred with the 1990 meteorological data set and excluded 107 calm hours from the annual average. This represents 1.2% of the data. The maximum annual PM_{10} concentration also occurred with the 1990 data set. The maximum 24-hour PM_{10} concentration occurred with the 1986 data set. However, the maximum 24-hour concentration was not averaged over a time period that included a calm. This may be verified in the modeling output files. If a short term average includes a calm period, a lower case c follows the reported concentration. Therefore, the lack of 2.6% of the meteorological data in 1986 had no effect on the result. This was equally true for all the short term averages (24-hours and less) evaluated for this facility.

87. Given this number of days and given that particulate matter once inhaled into the lungs causes damage at that moment and chronically, where have you taken this into consideration for protection of public health?

See response to CN 5, above.

88. Could the public know of the location of the "program" to prevent an accidental release or rupture of gas from the natural gas pipeline to the plant, which in an industrial accident in another state to another power plant caused considerable damage?

Natural gas pipeline operation is regulated by the Oklahoma Corporation Commission.

89. On comment 66 from the comments on the draft permit dated December 27, 2000, would the DEQ please provide papers showing the effects of the pesticides and their breakdown products are insignificant, and that this does not, in any way break the insecticide laws that are already in place?

See response to CN 11, above.

90. *Because of the danger to public health of the pesticides previously eluded to, why was modeling not carried out for pesticides in view of the danger to public health? The fact wet deposition is "not a guideline feature of ISC3" is not a reason not to do it considering the extensive number of programs for modeling that have been used between the first permit and it's modification. Please see the paper "Air Quality Issues" and "Effects of Particulate Air Pollution on Children" so that you can't just say that "gravitational settling is discounted with particle sizes 10 micron and smaller because particle size is extremely important as far as the health concern are involved. It would seem simpler for the DEQ just to ask the power plant company to clean up the water as they do for turbines. Why has this not been done and why is the DEQ not making an allowance for the health effects here?*

See response to CN 11, above.

91. *The EPA "has commented that BACT should be 2.0 PPM VD NOx at 5-PPMVD ammonia and that they don't expect the 5-PPMVD –ammonia slip to be an issue"(EPA Region 1). The air pollution control district, San Luis Obispo County also believes that these levels are achievable at the Duke Energy Morro Bay limited liability corporations power plant. The district also understands that SCR vendors will guarantee 2.0 PPMVD NOx F5-PPMVD ammonia. For these reasons the BACT emissions limit will be set at "2.0 PPMVD NOx with 5-PPMVD-ammonia slip". This seems to be the BACT standard for the United States, why is it her in Oklahoma that we have a plant which is similarly in an attainment area, and cannot match that plants BACT for it's attainment area status. Even Duke Energy claimed that the BACT should be 2.5 PPMVD with a 5 PPMVD ammonia slip for NOx.*

See response to CN 4, above.

92. *EPA district 1 with regard to the Morro Bay power plant has concluded that BACT for CO emissions should be 2.0 PPMVD at 15% O2 an a 3 hour average. They concluded that the design of the oxidation catalyst for maximum acrolein control will result in the ability to control CO below the 2.0 ppmvd on a 3 hour average. The Arcadia permit shows a similarly high value for that toxic material acrolein, so why is not our DEQ defending us as the EPA have done the citizens for Morro Bay in region 1?*

See responses to CN 4, 5, and 11, above.

93. *Is there a condition which requires monitoring for both the emissions associated with the ammonia slip as well as the ammonia injection rate? If not, why not?*

Standard Condition Section I. C. requires compliance with all conditions of the permit. Any permit noncompliance constitutes a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, for revocation of the approval to operate under the terms of the permit, or for denial of an application to renew the permit.

94. We would hope that the DEQ, State of Oklahoma agrees that oxidation catalyst control VOC and CO emissions and both pollutants can be considered ozone precursors, although CO plays a much smaller role in ozone generation than does VOC. In light of this, why is the DEQ not requiring catalytic oxidation not only to control VOCs and CO, but also to some degree particulate matter and other hazardous pollutants?

See response to CN 4 and 13, above.

95. We would hope that the DEQ would agree that the VOC limit in this permit is not BACT. The VOC emissions levels lower than 2.0 ppmvd have been recorded in source tests; the Sutter power plant and the La Paloma generation plant were granted at 1.0 ppmvd and 1.1 ppmvd respectively. Does not the PSD's top down BACT analysis require the DEQ to use these lower levels?

DEQ does not agree. See page 11 of the draft permit memorandum for the VOC BACT discussion and response to CN 4, above.

96. Since start up and shut down emissions are considerably greater than what the permit should allow, I would argue that start up emissions should be subject to BACT because of the new data on particulate matter and other health issues identified earlier in the first hearing. Pesticides and heavy metals can immediately damage cells, thus controlling emissions even in a very limited time frame is justified. Why does the Oklahoma DEQ think that the emissions testing that they can require even begins to satisfy this problem?

See responses to CN 7 and 11, above.

97. Has the applicant provided all the vendor guarantees for all the criteria and other emissions from their vendor? If so, are they on file where the public can see them or has the power plant company not even specified the turbine or the vendor at this juncture?

See response to CN 117, 118, 119, 120 and 121, below.

98. Because PM10 emissions are so important, does the DEQ require them to be performed at 3 load levels: full gas turbine load with duct firing, full load without duct firing and partial load without duct firing? If not, why not?

See Specific Condition number 12 for PM_{10} testing requirements for the turbines.

99. For a similar power plant the San Luis Obispo district is required the toxic best available control technology (TBACT) emissions control in the form of an oxidation catalyst. The compounds acrolein, formaldehyde, and acetaldehyde will be controlled by this catalyst. Why aren't we using an oxidation catalyst and at present without the oxidation catalyst, what is the health hazard index for this plant?

See responses to CN 4 and 11, above.

100. How are sulfur dioxide emissions being watched if both sulfur content and the gas usage rates are being measured, then mass balance can determine SO2 emissions by assuming 100% conversion of sulfur to SO2. Is this being required for this plant, and if not why not? And because of the spikes and valleys of sulfur in the natural gas, why is not continuous emission monitoring system being required?

See responses to CN 5, 25, 29, and 222.

101. According to the paper we have submitted, PM2.5 is deadly. Why is this not monitored?

All required and appropriate record keeping for this facility is contained in the specific conditions. See page 25 of the draft permit memorandum for the discussion of particulate matter BACT. See also response to CN 5 above.

102. Since the Morro Bay permit requires that a permit condition limiting quarterly emissions is appropriate there, why is it not appropriate for the Arcadia limited liability partnership plant?

See response to CN 31, above.

103. Why has the DEQ not added a toxic emissions source testing requirement to the conditions as Morro Bay has? They say "prior to granting a permit to operate, the district will insure that the new plant does not pose a significant health risk. If the new risk estimates are above the significance level changes to the plant's equipment and/or operating practices will be required, which may include further eliminating start ups".

This facility has been required to abide by all appropriate federal and Oklahoma state rules and regulations. California has its own separate state requirements. Also, see response to CN 11, above.

104. Why is there not conditioning limiting ammonia slip to 12.75 pounds per hour and 306 pounds per day as is found in the Morro Bay permit in their attainment area?

See response to CN 103, above.

105. Could you please let the citizens know what the design of the selective catalytic reduction system is at the present time? We feel that a requirement for ammonia injection based on catalyst temperature is a reasonable request. Will the DEQ add this as a condition please?

Information in the possession of DEQ regarding the SCR system is contained in the permit application and is available for review pursuant to the Oklahoma Open Records Act. The requested condition is not necessary. See response to CN 33, above.

106. Why is ther not a condition like at Morro Bay as follows, "each gas turbine and related HRSG shall be abated by the properly operated and properly maintained selective SCR system whenever fuel is combusted at those sources and the catalyst bed has reached minimum operating temperature"?

See responses to CN 33 and 36 above.

107. Is there a condition stating that the equipment should be fired exclusively on natural gas with a specified sulfur content? If not, why not?

Yes, see Specific Condition number 6 in the draft permit.

108. Is there a continuous monitoring system to record the mole ratio of Injected ammonia to exhaust stack NOx? Of these individual data points are not required, than why aren't they required given that they are required in other starts like California?

See response to CN 39 above.

109. Has the question added a condition to require a plan and procedure to ensure RLP is not omitted (rust like particulate)?

It is unclear what this comment says. All appropriate types of particulate matter have been considered and included in the draft permit.

110. "Emission factors for the turbines are based on manufacturer's guarantees (NOx and CO values for the turbines are based on parts per million by volume, dry basis, corrected to 15% oxygen), based on 8,760 hours per year operation."
What is the exact language of the turbine manufacture's guarantee? Provide copies of the manufacturer's guarantee documents.

The permit applicant submitted estimated emissions that were based upon information it received from the vendor. ODEQ utilized the estimated emissions provided by the permit applicant in setting the enforceable emissions limitations contained in the permit. The stack emissions from each combined cycle unit have been guaranteed to be in compliance with the permitted emissions limits. The guarantees provided by the combustion turbine generator (CTG) vendor and by the heat recovery steam generator (HRSG) vendor are contained in the purchase order documents that are considered confidential and proprietary. ODEQ is not in possession of any of these confidential and proprietary documents. Information regarding the contents of these documents was provided to ODEQ by the permit applicant. The CTG vendor and HRSG vendor have provided guarantees for NO_x, CO, VOC, SO_2, PM_{10}, and NH_3 slip that support the stack emissions guarantees provided for the combined cycle units.

111. What does the manufacturer guarantee to do if the emissions are higher than specified?

The manufacturer is required to adjust and/or modify its equipment until the stack emissions limits are met.

112. What are the conditions of the guarantees?

The manufacturers' emissions guarantees are conditioned on the combustion of natural gas having specified sulfur content and range in composition, in the design temperature range of 10 ^{0}F to 98 ^{0}F.

113. How are the manufacturer's emission guarantees verified? How often? Who does the measurements? How and where are records of these verifications kept?

Compliance with the permitted stack emissions limits are verified at plant commissioning and periodically thereafter, as required by ODEQ. An independent testing company will be engaged to conduct the tests and to prepare the test reports. The tests are conducted in accordance with USEPA standards and copies of the test reports are kept at the project site and at ODEQ. Continuous emissions monitoring system (CEMS) equipment will be installed on each HRSG stack, then calibrated and certified by an independent testing company. The CEMS equipment will continuously monitor and record the emissions from the HRSG stacks during operations, with reports of those emissions provided to the ODEQ as required by the air permit.

114. *What does dry basis mean? Does this assume no humidity? Does the emission modeling used in preparing this application, take into account the variability of humidity?*

Dry basis means no water vapor content of the gas or mixture of gases in the stack effluent (the terms humidity and relative humidity are usually reserved for description of atmospheric conditions). The use of dry basis is conservative, because adding moisture content would decrease the density of the effluent mixture.

115. Is 15% oxygen the ambient level of oxygen? Why are values corrected to 15% oxygen?

The passage to which this comment refers has to do with the turbine-exhaust/stack-gases. No comparison to ambient or atmospheric conditions is relevant. Good combustion practice (required by environmental rules) has the goal of complete combustion of all fuel in the air-fuel mixture. This is accomplished by supplying excess oxygen (air) to the combustion process. As a result the exhaust/stack-gases will always contain about 10% to 20% oxygen, and 15% is an average value for oxygen content of this gas mixture. Thus 15% oxygen concentration is a valid adjustment to bring calculated concentrations into close correspondence with actual stack conditions.

116. Provide copies of everything used in determining your answers to these questions. Provide these in an electronic form when the vendor or other source has made them available to you in that form or you already have this information in that form. This information will all be considered an integral part of your answers.

If you choose to exclude anything used in answering these questions, list the information used and the reason for excluding it. Explain how this permit can be evaluated without it.

This comment requests copies of every document used in responding to these comments. The public comments process on a permit modification is not the proper vehicle for obtaining agency records. Further, the number of documents potentially responsive to this request is too voluminous to attach to the Department's responses to comments. However, requests for specific documents and records can be made by sending a written request specifying the documents requested to:

Department of Environmental Quality
Air Quality Division
Request for Records
P.O. Box 1677
Oklahoma City, OK 73101-1677

Please include a contact phone number and address on the written request. Copying charges in the amount of $.25 per page will be assessed; further, search fees may also be assessed as authorized by law.

117. "The turbine vendor provided emissions estimates for 100% load at 10°F, 60°F, and 98°F." Who is the vendor of the turbines?

General Electric is the vendor of the CTGs.

118. Who is the vendor contact person or persons you used for asking technical questions?

The primary vendor contact person for the owner is Mr. D.V. Syngle, Director of Fossil Power Engineering, InterGen.

119. What is the contact person or persons phone, fax, address and email addresses?

InterGen North America, One Bowdoin Square, Boston, MA 02114, Tel: 617-747-1754, Fax: 617-747-7138.

120. What are the complete technical specifications for each turbine?

Each of the four General Electric combustion turbines is GE Model 7FA machine with dry low NOx (Model DLN 2.6) combustors, designed for natural gas firing only. Each combustion turbine is rated at approximately 160 MW electrical output (at ISO conditions), generated at 18 kV, 60 Hz.

121. Why aren't they included as part of the permit?

The permit includes information pertinent to the calculation of emissions, and the complete technical specifications contain much information unrelated to emissions. Therefore, the complete technical specifications are not included in the permit. The draft permit has been modified to include this information.

122. What were the emission rates at each temperature?

The emissions rates of each of the combined CTG/HRSG units are provided in the application for air permit, as amended from time to time, which is a matter of public record.

123. Which temperature had the highest emission rate?

The highest lb/hr emission rate for NOx, CO, SO_2, and NH_3 slip is at 10 ^oF. The highest lb/hr emissions rate for VOC and PM_{10} is at 60 ^oF.

124. Does the vendor provide documents, software, databases or services to determine emissions?

ODEQ is informed and believes that the vendor provided documents to the permit applicant containing estimates and guarantees of air emissions for this project but did not provide software, databases or services. ODEQ does not have these documents in its possession.

125. What documents, software, databases or services does the vendor provide for determining emissions?

The vendor will provide technical assistance services to the facility at the project site, to tune the performance of their equipment, prior to and during plant performance and emissions testing.

126. Did you use any documents, software, databases or services provided by the vendor or other source for determining emissions? If so, what was used?

The vendors provided documents to the permit applicant containing emissions rates for this project at the requested temperature conditions. ODEQ does not have these documents in its possession.

Provide copies of everything used in determining these emissions with your answers to these questions. Provide these in electronic form, when the vendor or other source has made them available to you in that form or you already have this information in that form. This information will be considered an integral part of your answers.

If you choose to exclude anything used in determining these emissions, list the information used and the reason for excluding it. Explain how this permit can be evaluated without it.

See response to CN 110 and 116, above.

127. "Emission from the emergency boiler were based on vendor emissions data." Who is the vendor of the emergency boiler?

Foster Wheeler is the vendor of the auxiliary boiler.

128. Who is the vendor contact person or persons you used for asking technical questions?

The primary vendor contact person for the owner is Mr. D.V. Syngle, Director of Fossil Power Engineering, InterGen.

129. What is the contact person or persons phone, fax, address and email addresses?

InterGen North America, One Bowdoin Square, Boston, MA 02114, Tel: 617-747-1754, Fax: 617-747-7138.

130. What are the complete technical specifications for the emergency boiler?

There is one Foster Wheeler, natural gas fired, auxiliary boiler (Model No. AG-5060 package boiler), with low NOx burners, rated for up to 93 MMBtu/hr heat input rate. The steam conditions are 200-psig pressure at 650 ^oF temperature.

131. Why aren't they included as part of the permit?

See response to CN 121, above. The draft permit has been modified to include this information.

132. Were emission rates determined at different temperatures?

The emission rates are guaranteed over the design temperature range of 10 ^oF to 98 ^oF.

133. Were emission rates determined at 100% load at 10 ^oF, 60 ^oF, and 98 ^oF?

The emission rates are guaranteed over the 100 % load at design temperature range of 10 ^oF to 98 ^oF.

134. What were the emission rates at each temperature?

At each of these temperatures, the emissions rates are guaranteed not to exceed 0.075 lb/MMBtu of NO_x, 0.07 lb/MMBtu of CO, 0.0075 lb/MMBtu of VOC, and 0.00531 lb/MMBtu of PM_{10}.

135. Which temperature had the highest emission rate?

See response to CN 132, 133 and 134, above.

136. Does the vendor provide documents, software, databases or services to determine emissions?

ODEQ is informed and believes that the vendor provided documents to the permit applicant containing emissions guarantees for this project but did not provide software, databases, or services. ODEQ does not have these documents in its possession.

137. What documents, software, databases or services does the vendor provide for determining emissions?

The vendor will provide technical assistance services to the facility at the project site, to tune the performance of the equipment, prior to and during plant startup and testing.

138. Did you use any documents, software, databases or services provided by the vendor or other source for determining emissions? If so, what was used?

The vendors directly provided the emissions rates which apply over the requested design temperature range and which were used for the air modeling. ODEQ is not in possession of these documents.

> *Provide copies of everything used in determining these emissions with your answers to these questions. Provide these in an electronic form, when the vendor or other source has made them available to you in that form or you already have this information in that form. This information will all be considered an integral part of your answers.*
>
> If you choose to exclude anything in determining these emissions, list the information used and the reason for excluding it. Explain how this permit can be evaluated without it.

See response to CN 110 and 116, above.

139. *"Emissions from the diesel generator were based on AP-42 (10/96), Section 3.4."*
Who is the vendor of the diesel generator?

The permit applicant has elected not to install a diesel generator. The draft permit has been modified to reflect this change.

140. Who is the vendor contact person or persons you used for asking technical questions?

See response to CN 139, above.

141. What is the contact person or persons phone, fax, address and email addresses?

See response to CN 139, above.

142. What are the complete technical specifications for the diesel generator?

See response to CN 139, above.

143. How is someone supposed to know what AP-42 (10/96), Section 3.4 is unless you include it in the permit?

AP-42 is one of a series of publications of the EPA related to various aspects of air pollution and its control. AP-42 is a document used by air professionals to aid in the calculation of emissions into the atmosphere from many types of facilities/sources. Section 3.4 is entitled *Large Stationary Diesel And All Stationary Dual-fuel Engines.* (10/96 is the revision date of the version used, usually the most recent version). This information is available at the EPA website. The section contains information about how to apply the emission factors presented therein.

144. How are the emissions determined from AP-42 (10/96), Section 3.4?

See response to CN 139, above.

145. Include documentation for AP-42 (10/96) in your answers.

See response to CN 139, above.

146. Were emission rates determined at different temperatures?

See response to CN 139, above.

147. Were emission rates determined at 100% load at 10°F, 60°F, and 98°F?

See response to CN 139, above.

148. What were the emission rates at each temperature?

See response to CN 139, above.

149. Which temperature had the highest emission rate?

See response to CN 139, above.

150. Does the vendor provide documents, software, databases or services to determine emissions?

See response to CN 139, above.

151. What documents, software, databases or services does the vendor provide for determining emissions?

See response to CN 139, above.

152. Did you use any documents, software, databases or services provided by the vendor or other source for determining emissions? If so, what was used?

See response to CN 139, above.

Provide copies of everything used in determining these emissions with your answers to these questions. Provide these in an electronic form, when the vendor or other source has made them available to you in that form or you already have this information in that form. This information will all be considered an integral part of your answers.

If you choose to exclude anything used in determining these emissions, list the information used and the reason for excluding it. Explain how this permit can be evaluated without it.

See response to CN 116, above.

153. "Emissions from the diesel-power water pump were based on AP-42, Section 3.3." Who is the vendor of the diesel-power water pump?

The vendor for the diesel engine on the diesel-driven fire water pump is Clarke USA.

154. Who is the vendor contact person or persons you used for asking technical questions?

The primary vendor contact person for the owner is Mr. D.V. Syngle, Director of Fossil Power Engineering, InterGen.

155. What is the contact person or persons phone, fax, address and email addresses?

InterGen North America, One Bowdoin Square, Boston, MA 02114, Tel: 617-747-1754, Fax: 617-747-7138.

156. What are the complete technical specifications for the diesel powered water pump?

There is one diesel powered fire water pump, provided as a backup to the electric motor driven fire water pump. The diesel engine is Clarke USA Model No. JDFP-06WA. The engine is being supplied to Clarke USA by John Deere (6081 Series) and is rated at 250 HP.

157. How is someone supposed to know what AP-42 (10/96), Section 3.3 is unless you include it in the permit?

The title to AP-42 Section 3.3. is *Gasoline and Diesel Industrial Engines*. See response to CN143 regarding where to find AP-42 sections.

158. How are the emissions determined from AP-42 (10/96) Section 3.3?

See response to CN 157 above.

159. Include documentation for AP-42 (10/96) in your answers.

See response to CN 157 above.

160. Were emission rates determined at different temperatures?

Emissions rates for the diesel powered fire water pump were determined using USEPA Publication AP-42 (10/96), Section 3.3. The AP-42 emissions rates are not determined upon temperature.

161. Were emission rates determined a 100% load at 10°F, 60°F, and 98°F?

No. Emissions rates for the diesel powered fire water pump were determined using USEPA Publication AP-42 (10/96), Section 3.3. The AP-42 emissions rates are not determined upon temperature.

162. What were the emission rates at each temperature?

USEPA Publication AP-42 provides emissions rates for diesel powered fire water pumps. The modeling for the permit application was based on emissions rates for an assumed 300 BHP diesel engine. Those emissions rates are 9.3 lb/hr of NOx, 2.0 lb/hr of CO, 0.87 lb/hr of SO_2 (based on 0.4% by weight sulfur in fuel), 0.75 lb/hr of VOC, and 0.66 lb/hr of PM_{10}.

163. Which temperature had the highest emission rate?

The AP-42 emissions rates are not determined upon temperature.

164. Does the vendor provide documents, software, databases or services to determine emissions?

The vendor has not provided documents, software, databases or services to determine emissions. The emissions are based on the rates published in USEPA Publication AP-42.

165. What documents, software, databases or services does the vendor or other source provide for determining emissions?

See responses above.

166. Did you use any documents, software, databases or services provided by the vendor or other source for determining emissions? If so, what was used?

The modeling for the air permit application was based on emissions estimated determined from USEPA Publication AP-42.

> *Provide copies of everything used in determining these emissions with your answers to these questions. Provide these in an electronic form, when the vendor or other source has made them available to you in that form or you already have this information in that form. This information will all be considered an integral part of your answers.*
>
> If you choose to exclude anything used in determining these emissions, list the information used and the reason for excluding it. Explain how this permit can be evaluated without it.

See response to CN 116 above.

167. *"Emissions from the cooling towers were based on a circulations rate of 102,000 GPM, a drift ratio of 0.0005%, and a total solids content of 3,075 mg/liter."*

    Who is the vendor of cooling towers?

Psychometric Systems, Inc. is the vendor of the cooling towers.

168. Who is the vendor contact person or persons you used for asking technical questions?

The primary vendor contact person for the owner is Mr. D.V. Syngle, Director of Fossil Power Engineering, InterGen.

169. What is the contact persons phone, fax, address and email addresses?

InterGen North America, One Bowdoin Square, Boston, MA 02114, Tel: 617-747-1754, Fax: 617-747-7138.

170. What are the complete technical specifications for the cooling towers?

There are four, 5-cell cooling towers, each rated for a circulating water flow of up to 102,000 GPM. The towers are of wood frame construction and include drift elimination equipment. The specified and guaranteed drift rate is 0.0005%. The draft permit will be changed to include this information.

171. Were emission rates determined at 100% load for 10°F, 60°F, and 98°F?

The drift emission rate from the cooling towers is guaranteed over the temperature range of 10 - 98 °F.

172. What were the emission rates at each temperature?

The drift emission rate of 0.0005% from the cooling towers is guaranteed over the temperature range of 10 - 98 °F.

173. Which temperature had the highest emission rate?

The circulating water flow rate and drift emission rate will be highest at the highest ambient temperature.

174. Does the vendor provide documents, software, databases or services to determine emissions?

ODEQ is informed and believes that the vendor provided documents to the permit applicant containing the drift emissions rate of 0.0005%. ODEQ does not have these documents in its possession.

175. What documents, software, databases or services does the vendor or other source provide for determining emissions?

The vendor will provide technical assistance services to the facility at the project site during plant startup and testing.

176. Did you use any documents, software, databases or services provided by the vendor or other source for determining emissions? If so, what was used?

The vendors directly provided to the applicant the drift emissions rate that applies over the design temperature range.

Provide copies of everything used in determining these emissions with your answers to these questions. Provide these in an electronic form, when the vendor or other source has made them available to you in that form or you already have this information in that form. This information will all be considered an integral part of your answers.

If you choose to exclude anything used in determining these emissions, list the information used and the reason for excluding it. Explain how this permit can be evaluated without it.

See response to CN 116 above.

177. What were the reasons for increasing the cooling tower circulation rate from 58,000 to 102,000 GPM? Why was this change necessary? Please provide documentation the vendor or other source provided to you to support this change.

With the increase of the plant output from 1100 MW to 1220 MW, additional steam is generated in the HRSGs and that steam must be condensed in the surface condensers. The circulating water flow rate was increased to effectively capture the heat that is rejected in the surface condensers.

178. "The auxiliary boiler will be limited to 3,000 hours per year." Why did and auxiliary boiler have to be increased from 20 MMBTUH to 93 MMBTUH? Could the auxiliary boiler be running 24 hours a day during the summer months?

The auxiliary boiler was increased to 93 MMBtu/hr in order to provide enough steam to maintain a vacuum on each of the four condensers and to maintain heat in each HRSG steam drums when the combined cycle units are shutdown, but in standby mode. Doing so allows for a faster and more efficient startup of each combined cycle unit. The auxiliary boiler will be running only when the units are in a hot stand by mode and its running is not dependent on the ambient weather conditions.

179. "Tier II public review, best available control technology (BACT), and ambient impacts analyses are also required." What criteria were used to determine Redbud was a Tier II application? Provide supporting documentation.

See response to CN 1 above.

180. Are these criteria in adherence with 40 CFR 70?

Yes. The criteria in OAC 252:100-8-7.2(b)(2)(A)(iii) are consistent with the criteria required in 40 CFR 70.7(e)(4) [, although the Part 70 criteria are not mandatory for construction permits].

181. "Emissions from the cooling towers were calculated assuming a drift ratio (ratio of lost ware to total water input) of 0.0005%, a water input of 102,000 GPM per tower, and a total solid content of 3,075 ppm." Provide the documentation supporting the .0005% drift ratio estimate.

DEQ is informed and believes that the cooling tower vendor has provided a guarantee of the 0.0005% drift emissions rate to the permit applicant. The guarantee is contained in documents that are considered confidential and proprietary. ODEQ is not in possession of these documents.

182. Provide documentation supporting a total solid content of 3,075 ppm.

See Table 2-4 Intergen – Redbud Power Plant Summary of Emissions Associated With The Proposed Cooling Towers (1220 Megawatt Plant) in the Request For Amendment PSD Permit (#2000-090-C(PSD)).

183. "The application conservatively assumed all TSP was PM_{10}. EPRI's report entitled User's Manual - Cooling Tower Plume Prediction, state on page 4-1 that this particulate ranges in size between 20 and 30 micron, thus none of the TSP would be expected to be PM_{10}."

Provide a copy of the User's Manual - Cooling Tower Plume Prediction.

This publication is copyrighted. Copies are can be obtained by contacting the Electric Power Research Institute (EPRI) at askepri@epri.com.

184. "Emissions from the auxiliary boiler are calculated using factors from the vendor." Provide vendor's documentation of the factors.

ODEQ is informed and believes that the vendor's documentation provides guaranteed emissions rates of 0.075 lb/MMBtu of NO_x, 0.07 lb/MMBtu of CO, 0.0075 lb/MMBtu of VOC, and 0.00531 lb/MMBtu of PM_{10}. ODEQ is not in possession of these documents.

185. *"Redbud Energy LP identified these technologies and emissions data through a review of EPA's BACT/LAER Clearinghouse (RBLC), as well as EPA's NSR and CTC website, recent DEQ BACT determinations for similar facilities, and vendor-supplied information."*

Specifically what data was used from these sources? Why isn't this data part of the documentation for the permit? How can a person assess, evaluate, analyze or review this permit without this information?

The RBLC contains facility, process and pollutant information that reflect RACT, BACT, and LAER determination by permitting agencies. Agencies are required to submit LAER decisions to the RBLC, but all other submissions are still voluntary at this time. To access the RBLC Web you need a personal computer, internet browser software, and access to the World Wide Web through an Internet provider. Access the RBLC by going to the Clean Air Technology Center (CATC) Web page and clicking on the RBLC Web logo. The CATC Web address is: <http://www.epa.gov/ttn/catc/>

186. Provide all documentation from these sources used in preparing this application.

ODEQ cannot provide the requested information because it is too voluminous. Further, the clearinghouse which is a website database, is continually being updated. This means that information provided from the website today would not be the same information on the website tomorrow. See response to CN 185 above for directions to the RBLC website.

187. Why would recent DEQ BACT determinations not be included in the RACT/BACT/LAER Clearinghouse (RBLC)? Would this mean other recent BACT determinations are not included in the RACT/BACT/LAER Clearinghouse (RBLC)?

RBLC has not reviewed Oklahoma's files since October 2001. Since that time, about 20-25 of the most recent BACT determinations have been added and are waiting for review. As soon as RBLC contractors review the information those permits will be issued to their website. At this time, individual searches at the RBLC website (http://cfpub1.epa.gov/rblc/cfm/rbfind.cfm) may be used to find these permits starting with OK-0029 through OK-0054.

188. A lexicon of the technical, obscure or foreign words of a work or field. All your permits need a glossary with clear definitions. For example:

PSD - prevention of significant deterioration of air quality. The mission statement of the Clean Air Act. Only approving permits for air pollution sources when they do not significantly increase the existing air quality. The intent was to consider the impact of all automobiles not just one tailpipe or all power plants not just one plant with twenty five stacks when making this determination.

The number of definitions potentially applicable to air permits is too high to include in permits issued by the Department. However, there are website that contain plain English glossaries of the relevant terms. The EPA has such a website (http://www.epa.gov/oar/oaqps/peg_caa/pegcaa10.html).

189. "The Redbud Power Plant combustion turbine/HRSG units will be subject to a NOx emission limit of 3.5 ppmvd at 15% oxygen utilizing Selective Catalytic Reduction (SCR). There are potential adverse environmental impacts associated with this control technology, primarily from ammonia slip which will be limited to 7 ppm at 15% oxygen. DEQ believes that SCR and DLN with 3.5 ppmvd corrected to 15% oxygen for the turbines and duct burners firing will fulfill the BACT requirement, with consideration given to the technical practicality and economic reasonableness of minimizing emissions."

Provide all documentation from all sources you used in making this determination. Describe in detail your criteria and calculations for choosing 3.5 ppmvd. Describe how this compares with Oklahoma DEQ BACT determinations made during the last four years.

BACT examples>

A Dry Low NOx(DLN) w/SCR (with the duct burner firing) achieves a 2.5 ppmvd emission concentration on a GE7FA turbine.

Satsop Combustion Turbine Project - Elma, Washington
Prevention of Significant Deterioration Permit - August 28, 2001
(Location is in an attainment area)

A Dry Low NOx (DLN) w/SCR (with the duct burner firing) achieves a 2.0 ppmvd emission concentration on (NOx) and 2.0 ppmvd emission concentration (CO) on a GE7FA turbine.

The system has an ammonia injection system (5 ppmvd ammonia slip), a selective catalytic reduction NOx system located within the HRSG and an oxidation catalyst. The system has a continuous emission monitoring system (CEMS) designed to continuously monitor and record the NOx and CO concentrations to fifteen (15) percent oxygen (O_2) on a dry basis.

Duke Energy Morrow Bay LLC - Morro Bay, California
Final Determination of Compliance - August 30, 2001
(Location is in attainment area)

The 3.5 ppmvd emission rate was put into the permit because it was the lowest feasible emission rate for a facility of this type and size. The emission rate is lower than ODEQ has required in the last four years at facilities of this type and size. ODEQ cannot produce the documents requested as the number of documents potentially responsive to this request is too voluminous. However see response to CN 116 above regarding the procedure for obtaining specified documents.

Further, this comment implies that BACT in other states, like California, determine what BACT is in Oklahoma. That is not the case. BACT standards are different in each state and geographical location. For example, the BACT standard in California is equivalent to LAER. LAER is a standard that is not applicable in Oklahoma and therefore cannot be used to determine BACT in Oklahoma. The BACT determination contained in the permit modification at issue is in full compliance with the BACT standard applicable in Oklahoma.

190. SCONOX™

> *"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 degredation that is experienced by any catalyst in a turbine exhaust stream. This has led to reported outage in some cases due to catalyst fouling in the early stages of operations."*
>
> *Provide documentation to support the reported outages. Were the SCONOX systems designed never to exceed 80% capacity?*

This comment refers to the potential for SCONOX catalyst fouling in the early stages of operation. Environmental Science Services, Inc., with offices in Providence, R.I., and Wellesley, Mass., issued a paper on this issue that can be obtained from their web site at www.essgroup.com. Page 4 of the paper states, "The proprietary precious metal catalyst experienced problems with sulfur build-up while firing natural gas after only six months of operation at the Sunlaw plant."

191. "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 and will be precluded from further consideration in the BACT analysis."

> *Provide complete documentation for your cost estimate. It is twice as high as other estimates.*
>
> *BACT example>*

Only one large source in California has a permit which includes SCONOX as a control for three or four turbines. The fourth turbine can be controlled using either SCONOX or SCR. Therefore, SCONOX is considered technically feasible but unproven for large power plants such as the Satsop CT Project. Cost data submitted to Duke Energy by SCONOX's vendor indicates that annual costs would be $3,785,257 million per turbine resulting in an incremental cost of $12,870 per ton of nitrogen oxides removed.

Satsop Combustion Turbine Project - Elma, Washington
Prevention of Significant Deterioration Permit - August 28, 2001
(Location is in attainment area)

ODEQ verified the $26,000 cost estimate with the vendor Alstom Power. ODEQ does not know the source(s) of the information referenced and cannot therefore, explain the difference in the cost estimate.

192. *"The CO emission rate under maximum load conditions will be limited to 17.2 ppmvd for the combustion turbine when firing natural gas. 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). In addition, EPA Region VI recently commented for another gas-fired cogeneration plant permit that they expect to see CO at 22 ppm or less for combustion turbines."*

Provide all documentation from all sources you used in making this determination. Describe in detail your criteria and calculations for choosing 17.2 ppmvd. Describe how this compares with Oklahoma DEQ BACT determinations for the past four years.

BACT examples>

EFSEC agrees that catalytic oxidation in addition to combustion controls is BACT for CO control. CO emissions from each CT/HRSG exhaust stack of the project shall not exceed 2 ppmvd at 15% oxygen on an hourly average when pipeline quality natural gas is burned.

Satsop Combustion Turbine Project - Elma, Washington
Prevention of Significant Deterioration Permit - August 28, 2001
(Location is in attainment area)

A Dry Low NOx (DLN) w/SCR (with the duct burner firing) achieves a 2.0 ppmvd emission concentration on (NOx) and 2.0 ppmvd emission concentration (CO) on a GE7FA turbine.

The system has an ammonia injection system (5 ppmvd ammonia slip), a selective catalytic reduction NOx system located within the HRSG and an oxidation catalyst. The system has a continuous emission monitoring system (CEMS) designed to continuously monitor and record the NOx and CO concentrations to fifteen (15) percent oxygen (O2) on a dry basis.

Duke Energy Morrow Bay LLC - Morro Bay, California
Final Determination of Compliance - August 30, 2001
(Location is in attainment area)

It should be noted that the issue of BACT was fully litigated during the extensive hearing on the original construction permit. The comment and ensuing response are reiterations of matters that were resolved in the litigation. First, Oklahoma City is not near non-attainment for CO. Second, the comment is implying that BACT in other states (like California) determines what BACT is in Oklahoma. That is not the case. BACT standards are different in each state and geographical location. For example, the BACT standard in California is equivalent to the Lowest Achievable Emission Rate (LAER) standard. LAER is a standard that is not applicable in Oklahoma and therefore, cannot be used to determine BACT in this state. The BACT determination in the permit modification at issue is in full compliance with the BACT standard applicable in Oklahoma. See Section IV A CO BACT Review portion of the draft permit memorandum.

193. NAAQS Modeling

"The regulatory default option was selected such that USEPA guideline requirements were met."
What were the exact options for each setting of the program used when setting up the model? Provide documentation for the assumptions made. For example - why a particular temperature was chosen and entered as a setting.

There appears to be some confusion on the difference between data inputs and model options. For example, temperature would be a data input. There are no temperature options. The ambient temperature for each hour modeled is obtained from the meteorological data. The stack temperature is obtained from the applicant and assumes a worst-case operating scenario from the perspective of emissions and ground level concentrations. A model option directs the model to perform specific calculations. For example, choosing the concentration option directs the model to calculate the concentration of the pollutant. Each model option selected and datum inputted is documented in the publicly available modeling input and output files. Electronic files containing the modeling performed were made available during the prior administrative proceeding on the initial construction permit. Copies are available on CD-Rom and may be obtained from DEQ by contacting:

The Department of Environmental Quality
Air Quality Division
Request for Records
P.O. Box 1677
Oklahoma City, OK 73101-1677

There is a $25 cost of production assessed for each CD-Rom provided by DEQ.

The quoted statement from the memorandum of the permit refers to the initial control options within the ISCST3 program. Detailed information and guidance for the regulatory default options can be found in 40 CFR 51, Appendix W. By selecting the regulatory default, the following control options are not selected: toxic option, sampled chronological input model, effective depletion factor, gradual plume rise, no stack tip downwash, no buoyancy induced dispersion, include calm hours, allow missing met data.

The comment appears to be requesting information on all options and data input in the model, including and outside of the information listed above. The information requested is too voluminous to present as a response to a comment to the draft permit. The modeling was available during the preparation of the draft permit and during the public review period and is currently available to the public. However, for persons who are interested in learning how to reproduce the required modeling there are several modeling courses that are commercially available. DEQ can provide a list of some of these courses. Requests for this information can be made to the address provide above.

Documentation on all options may be obtained from 40 CFR 51 Appendix W and the “User’s Guide for the Industrial Source Complex (ISC3) Dispersion Models” EPA 454/B-95-003a and 454/B-95-003b, all of which may be obtained from http://www.epa.gov/ttn/scram.

194. “The ISCST3 model was used for all pollutants.” Why was the ISCST3 model chosen?

It is an approved model by EPA for the type of study required. It is the most often used and most often relied upon model for these types of facilities. It is a conservative model in that it tends to overestimate the effects of emissions rather than underestimate them. All states and EPA recognize this model as appropriate and acceptable for the types of modeling required for this application.

195. What are the gross error rates of predictions you made using ISCST3?

There are no regulatory requirements to perform case-by-case statistical analyses with an approved model. The model was designed to yield conservative results for precisely the type of source modeled. For information on model performance analyses please refer to “Protocol for Determining the Best Performing Model”, EPA 454/R-92-025, US EPA Office of Air Quality Planning and Standards, December 1992

For a detailed list of evaluation studies on the ISC3 models and preprocessors please refer to 40CFR Part 51, Appendix W, Appendix A. For additional information refer to "Model Parameter Sensitivity Analysis" Volumes 1 and 2, US EPA Region 6 Center for Combustion Science Engineering, May 23, 1997

196. What are the confidence levels of the predictions you have made with ISCST3?

Please refer to response to CN 195, above.

197. Were sensitivity studies made to evaluate the impact of the most significant variables when you used the ISCST3 model?

Sensitivity studies were conducted by EPA in the development of the model and in the development of model guidance. Please refer to response to CN 195, above.

198. Provide all documentation from all sources you used in preparing all inputs for the ISCST3model.

Meteorological Data:
Surface Data*- EPA Support Center for Regulatory Air Models, http://www.epa.gov/scram001/index.htm*
Mixing Height Data*- EPA Support Center for Regulatory Air Models, http://www.epa.gov/scram001/index.htm*
PCRAMMET (executable and guidance)*- EPA Support Center for Regulatory Air Models, http://www.epa.gov/scram001/index.htm, PCRAMMET User's Guide, EPA-454/B-96-001, Revised June 1999.*
Terrain Data:
7.5 minute Digital Elevation Model Data:*USGS, http://edcwww.cr.usgs.gov/doc/edchome/ndcdb/ndcdb.html*
SDTS2DEM (executable)*- http://data.geocomm.com/dem/*
Source Parameters: *Application for Permit 2000-090-C PSD and all subsequent submittals*
Model Options: *40 CFR Part 51 Appendix W*, User's Guide for the Industrial Source Complex (ISC3) Dispersion Models, EPA 454/B-95-003a and 454/B-95-003b, http://www.epa.gov/ttn/scram.

199. Describe the Aries system (database, software & scripts) and how it is used in preparing input for the ISCST3 model or any other model used in this application.

The Aries Database was not used in the preparation of this permit. The Aries Database is a standardized query from a snapshot of the Team Database. The Team Database is the Oklahoma Air Quality database, which maintains data on permit and enforcement activities as well as pollutant inventory data.

200. "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 increase in NOx and VOC emissions to predict increase in ozone concentrations."

Is the basis of Robert Scheffe's screening tables ever been the subject to academic peer review?

The comment contains a typographical error in the author's name. He is Richard D. Scheffe. His paper is <u>VOC/NOx Point Source Screening Tables,</u> September 1988, United States Environmental Protection Agency Office of Air Quality Planning and Standards_Technical Support Division Source Receptor Analysis Branch. Whether EPA requires academic review of its papers is unknown to ODEQ. This particular document is recognized by all states and EPA Regions as a useful tool to evaluate ozone impacts as was done on page 22 of the Redbud Memorandum for permit number 2000-090-C (M-1) (PSD).

201. *Have Scheffe's tables ever been verified against actual measurements? If so, provide documentation.*

Whether the Scheffe tables have ever been evaluated against actual measurements is unknown to the Department. It is not likely that this was done for it would not make sense to do so. The Scheffe tables were developed by using EPA's Reactive Plume Model. The Reactive Plume Model has undergone evaluation studies. Please refer to 40 CFR 51 Appendix W, Appendix B for documentation on the studies. The Scheffe tables merely rely on generic yet conservative background chemistry for urban or rural settings and conservative meteorology. Conservative means that they are likely to predict high ozone concentrations. The Scheffe tables are a screening method. Screening methods are intended to provide conservative rough estimates of impacts. Once you have established that the methodology will yield conservative results a site-by-site comparison to actual measurements holds little value.

202. Why aren't actual measurements used in making these determinations?

Actual measurements of the impact of a source on ozone concentrations are not available until after a source has constructed and begun operation. The use of predictive models allows the Department to evaluate the potential impact and take any appropriate steps to mitigate it.

203. Why aren't actual measurements made to verify Scheffe's predictions after a plant has started operating?

The Department maintains a monitoring network that continually monitors the impact of sources within the State. The Department may require source specific post construction monitoring for ozone in the event that preconstruction monitoring requirements are met. As two separate evaluations (Scheffe Tables and Environ "Assessments of the Ozone Impacts in the Tulsa-Oklahoma City Areas Due to Proposed New Sources") did not indicate that a problem would arise from this source, post-construction monitoring was not indicated and therefore, was not required.

204. What are the gross error rates of predictions made with Scheffe's tables?

The degree to which the model over predicts will vary from scenario to scenario and therefore, the degree to which this source's impacts were overestimated is unknown.

205. What are the confidence levels of predictions made with Scheffe's tables?

The department is unaware of any statistical analyses performed on the Scheffe tables indicating the degree to which the method over predicts concentrations of ozone.

206. Has Robert Scheffe ever written an academic paper or book on his screening tables?

See response to CN 203 above.

207. "The meteorological data used in the dispersion modeling analyses consisted of five years (1986, 1988, 1990, 1991) of hourly surface observations from the Oklahoma City, Oklahoma, National Weather Station and coincident mixing heights from Oklahoma City (1986-1988) and Norman, Oklahoma, (1990 and 1991)." Why were these years chosen?

These years represent the most recent, most nearly consecutive, and most readily available data.

208. Why wasn't data from (1999, 2000 or 2001) used?

A complete year of meteorological data from 2001 was not available on the date this comment was received (November 16, 2001). That fact aside, the use of post 1997 data would necessitate the use of data from an earlier period to meet the five year requirement, as data between 1992 and the spring of 1997 did not include cloud cover above 12,000 feet. Further, the data from 1996 forward is reported in the METAR reporting format and includes more calm periods than the previous reporting method. As the program cannot accurately predict concentrations for calm periods, and therefore leaves them out of all calculations, results based on recently recorded meteorology would rely on less data than that contained in the data set used.

209. Was the ISCST3 model run for all the days in (1986, 1988, 1990, 1991)?

Every day of the four years listed was included in the analyses. Meteorologically defined calm hours within days were not included in the analyses.

210. Were certain days used for the ISCST3 model? If so, which days and why were they selected?

All days were used.

211. "Further the applicant participated in the ozone impact study conducted by Environ (March 20, 2000). The study was done to assess the ozone impacts in Oklahoma due to proposed new electrical generating units (EUGs) in the region. CAMx was run for a 1995 Base Case emissions scenario and the model-estimated ozone concentrations were compared with the observed values of a June 1995 ozone episode."

"Additional analysis of the spatial distribution of the predicted and observed 1-hour and 8-hour ozone concentrations revealed the model exhibited a fairly good job of estimating the spatial patterns of the observed ozone concentrations."

"Emissions from the New Oklahoma City Sources were estimated to not increase ozone in the Tulsa-Oklahoma City area to above the 1-hour ozone standard in Oklahoma. As the New Oklahoma Sources are much less than 1 ppb, then they are estimated to have no measurable effect on peak 8-hour ozone concentrations in the Tulsa and Oklahoma City areas.

When you say "fairly good job of estimating spatial patterns of the observed ozone concentrations", just exactly how close were they? Provide documentation.

The model results met EPA's performance goals. The EPA goal for Peak Unpaired Accuracy in the one-hour standard is less than ± 20%. The episode modeled ranged from 2.2 to 9.5%. The EPA goal for hourly ozone statistics of the normalized bias and normalized gross error are less than ±15% and less than 35% respectively. The normalized bias for the modeled episode ranged from 1.3 to –8.1%. The normalized gross error for the modeled episode ranged from 9.9 to 16.2%. The data quoted is available in the publicly available Revised Final Report: Assessment of the Ozone Impacts in the Tulsa-Oklahoma City Areas Due to Proposed New Sources, April 20, 2000.

212. What were the gross error rates of ozone concentration predictions of the Environ CAMx model?

Please see CN 211, above.

213. What were the confidence levels of the ozone concentration predictions of the Environ CAMx model?

Photochemical model performance is not measured by confidence levels. For measures of performance levels see CN 211, above.

214. Did all New Oklahoma Sources participate in the study?

All known new major sources at the time of data gathering were included.

215. If not, which ones did not participate?

Sources, which submitted applications after January of 2000 were not included in the original study.

216. There are no photochemical grid modeling databases set up for estimating the ozone impacts in the Tulsa-Oklahoma City area. Is this true?

There are no complete modeling databases as yet set up for the Tulsa and Oklahoma City areas.

217. Why was the June 18-22, 1995 Dallas-Fort Worth CAMx photochemical modeling database used for analysis?

The domain of the analysis included a majority of Oklahoma. While this domain was not designed for an Oklahoma study it was readily adaptable.

218. Were the databases created state implementation plan (SIP) quality?

No.

219. Did the study say "estimates of attainment should be viewed with caution"? How can the Oklahoma DEQ, the EPA or the citizens of Oklahoma rely on results of this study? How does it comply with 40 CFR 70?

Page ES-7 of the study emphasizes that the databases are adequate to determine the relative contribution of the proposed new power plants. The model estimated absolute concentrations in an effort to overestimate any effect these new sources might have, therefore, any estimates of attainment or non-attainment should be viewed with caution. The purpose of the study was to determine what effect, if any, the proposed power plants would have on Oklahoma. Please read the final paragraph of page ES-8 for further discussion of the conservative nature of this study.

The are no regulatory requirements in Part 70 which would require this study.

220. 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 NO2, CO, SO2 and PM10. Neither pre-construction nor post-construction monitoring will be required for these pollutants. However, VOC emissions are greater that the 100 TPY monitoring significance level. Therefore ozone pre-construction monitoring is required. The existing National Air Monitoring System (NAMS) monitoring site (No. 41091037-1) located 8.4 km south and 22.2 km west of the facility will provide conservative monitoring data in lieu of pre-construction monitoring."*
>
> *If you don't take at least a year's worth of measurements of levels for criteria pollutants at the power plant site, how do you know what the historical levels were? This monitoring needs to be done before and after construction to insure accountability and compliance with the Clean Air Act. Provide documentation for your determination. Show how it complies with 40 CFR 70.*

In the PSD review process, an initial modeling analysis is conducted evaluating only the proposed emissions. The results of this analysis are then compared to two different significance levels. The first is a modeling significance level. If the predicted impacts exceed the modeling significance level then the source is required to do further analyses to insure that the source will not cause or contribute to significant deterioration in the area, as measured by the National Ambient Air Quality Standards and increment consumption levels.

The second significance level is the monitoring significance level. If the predicted impacts exceed the monitoring significance levels then pre-construction monitoring would be required. For ozone, the monitoring significance level is an emission rate of volatile organic compounds (VOC) rather than a modeled ozone concentration. While the proposed facility does not exceed the monitoring significance levels for PM_{10}, SO_2, NO_2, or CO it does exceed the monitoring significance level for ozone. The monitor selected for the pre-construction analysis is both conservative and representative of the area. This monitor is used directly with the Scheffe analysis to arrive at a conservative post-construction estimate.

Because NO_2 emissions are also precursors to ozone formation, the DEQ required that all of the proposed utilities be modeled with all existing point and area sources as well as road, non-road, and biogenic emissions sources. This modeling coupled with data from all of the ozone monitors in the state and modeled boundary conditions from Texas, determined that the proposed facilities would not cause an exceedance of the 1-hour standard nor have a measurable effect on the 8-hour standard. The requirement to do this modeling was above and beyond existing state and federal requirements.

The monitoring significance thresholds, like the modeling significance thresholds, were not crossed for any of the criteria pollutants other than ozone. Predicted impacts were not triggered for any of the criteria pollutants except ozone. For this reason pre-construction monitoring was required for ozone. Because of the network of monitors already in existence in and around the Oklahoma City Area, it was determined that pre-existing data from these monitors were adequate to meet the pre-construction monitoring requirement. Because no standards are threatened by the new source, post construction monitoring will not be required.

221. Isn't trying to monitor VOC emission levels from a location 8.4 km south and 22.2 km west of the facility just about as accurate as measuring the temperature, humidity and wind direction of Oklahoma University in Norman, Oklahoma in a hypothetical National Air Monitoring System in Mustang, Oklahoma.

The ambient Ozone site near Oklahoma Christian University is nearest and most representative for the applicable facility. It is also a site that has been in existence for a long time providing long-term trends data whether it is as accurate as comparing temperature, humidity and wind direction at OU with a site in Mustang (that does not exist) is not relevant to the permit modifications being reviewed. Also, monitoring VOC emissions in this permit is not required.

222. How can this be relied on? Please justify you determination. Provide complete documentation and include projected gross error rates and confidence levels.

Ambient Air Quality sites are selected for comparison to the NAAQS and for population exposure. Any error rates for specific monitors must fit certain criteria developed by the USEPA or the data is not considered valid. Any data collected for the above stated purpose is quality assured, validated, and placed into the National AIRS database if it meets EPA's criteria.

223. Morrow Bay Example>

A Dry Low NOx (DLN) w/SCR (with the duct burner firing) achieves a 2.0 ppmvd emission concentration on (NOx) and 2.0 ppmvd emission concentration (CO) on a GE7FA turbine.

The system has an ammonia injection system (5 ppmvd ammonia slip) a selective catalytic reduction NOx system located within the HRSG and an oxidation catalyst. The system has a continuous emission monitoring system (CEMS) designed to continuously monitor and record the NOx and CO concentrations to fifteen (15) percent oxygen (O2) on a dry basis.

Duke Energy Morrow Bay LLC - Morro Bay, California
Final Determination of Compliance - August 30, 2001
(Location in attainment area)

Why isn't a continuous emission monitoring system (CEMS) for NOx and CO required for this plant?

Continuous emission monitoring for NOx is required in the permit to insure compliance with these limits. This is to comply with the Acid Rain Program as defined under Title IV of the 1990 Clean Air Act Amendments, which establishes a national cap on sulfur dioxide emissions and targets reductions in both the sulfur dioxide and the oxides of nitrogen emissions. Nevertheless, CEMS for CO are not required under the Acid Rain Program.

224. What are the criteria your determination?

The permit reflects the applicable regulations in effect for this type of facility. The specific conditions of the proposed permit require that the facility not exceed the permit (performance) limits.

225. How do they comply with 40 CFR 70? Provide documentation for your answers.

CEMS for NOx are required under 40 CFR Part 75 to be used in the Acid Rain Program. They are not required under 40 CFR 70. Part 70 is an operating permit program which is not yet applicable to the facility. The facility will be required to obtain a Part 70 permit following commencement of operations.

Fees Paid

A fee of $500 is due, and $500 has been paid for this application for amendment.

SECTION VIII. SUMMARY

The applicant has demonstrated the ability to comply with the requirements of the applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance and enforcement issues concerning this facility. Issuance of the amended permit is recommended. Administrative amendments are afforded coverage by the permit shield in 252:100-8-6(d)[2].

[2] Changed by administrative amendment dated 04-29-04 in accordance with 252:100-8-7.2(a).

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Redbud Energy LP
Redbud Power Plant **Permit No. 2000-090-C (M-4) (PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on March 16, 2000, with additional information submitted June 1, 14, and July 27, 2000, and September 5 and September 28, 2001; and in conformity with the applications for amendment submitted November 14, 2002 and December 8, 2003. The Evaluation Memorandum dated April 29, 2004, 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:

Each of Four Combustion Turbines with Duct Burner Firing[3]			
Pollutant	**lb/hr**	**TPY**	**ppmvd[C]**
NO_X	34.5[A]	151.1	3.5 [A]
CO	97.5[B]	427.1	17.2[B]
VOC	16.2	71.0	N/A
SO_2	6.9	30.4	N/A
PM_{10}	27.9	122.2	N/A
Lead	0.001	0.001	N/A
H_2SO_4	0.6	2.6	N/A
Ammonia	25.5	111.7	7

[A] 3-hour rolling average.
[B] 1-hour rolling average.
[C] Ammonia, NO_x and CO concentrations are corrected to 15% O_2

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	6.98	10.46	43.63	10.91	9.30	2.32	--	--
CO	6.51	9.76	10.00	2.50	2.00	0.50	--	--
VOC	0.70	1.05	1.28	0.32	0.75	0.19	--	--
SO_2	0.27	0.40	5.89	1.47	0.87	0.22	--	--
PM_{10}	0.49	0.74	1.27	0.32	0.66	0.16	3.17	13.76

3 Table changed by administrative amendment dated 04-29-04 in accordance with 252:100-8-7.2(a)

2. The fuel-burning equipment shall use only pipeline-quality natural gas with 10 ppm or less sulfur except for the emergency diesel fire-water pump engine and emergency diesel generators, which shall burn diesel fuel with a maximum fuel sulfur content of 0.4 percent by weight.

3. A serial number or another acceptable form of permanent (non-removable) identification shall be on each turbine.

4. Upon issuance of an operating permit, the permittee shall be authorized to operate each combustion turbine with associated HRSG and 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 will be limited to 500 hours per year each.

5. The permittee shall incorporate the following BACT methods for reduction of emissions. Emission limitations are as stated in Specific Condition No. 1.

   a. Emissions from each combined cycle unit shall be controlled by properly operated and maintained Selective Catalytic Reduction maintaining levels as specified in Specific Condition #1.
   b. Emissions from the auxiliary boiler, emergency generator, and emergency diesel fire 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.

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

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

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

8. The duct burners are subject to federal New Source Performance Standards, 40 CFR 60, Subpart Da, and shall comply with all applicable requirements.

   a. 60.42a: Standard for particulate matter
   b. 60.43a: Standard for sulfur dioxide
   c. 60.44a: Standard for nitrogen oxides
   d. 60.46a: Compliance provisions
   e. 60.47a: Emission monitoring

f. 60.48a: Compliance determination procedures and methods
g. 60.49a: Reporting requirements

9. The permittee shall maintain a record of the amount of natural gas burned in the auxiliary boiler for compliance with NSPS Subpart Dc.

10. The permittee shall comply with all acid rain control permitting requirements and for SO_2 and NO_X emissions allowances of 40 CFR 72 - 75.

11. The permittee shall comply with one of the following: (1) Meet the general operating requirements in 40 CFR Part 75.10 for a NO_x Continuous Emission Monitoring System; or (2) Follow the 40 CFR Part 75 Appendix E NO_X Emissions Estimation Protocol for peaking units until such time the units are operated above the levels defining peaking load units. At such time, the permittee shall follow the 40 CFR Part 75 monitoring guidelines for non-peaking units and will install NO_X CEMs on combustion turbine/HRSG stacks no later than December 31st of the following calendar year per 40 CFR Part 75.12 (c)(2).

When operating with the CEMS each affected unit is authorized to comply with the Part 75 Acid Rain Program testing requirements in lieu of the Part 60 NSPS testing requirements for the CEMS. This includes Part 75, Appendix B, paragraphs 2.2.1 Linearity Check, 2.2.4 Linearity Grace Period, 2.3.1.1 Standard RATA Frequencies, and 2.3.1.2 RATA Grace Period. Notwithstanding these provisions, each affected unit shall complete a RATA at a frequency of not greater than eight (8) consecutive operating quarters.[4]

12. 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 and Subpart Da for the duct burners. [OAC 252:100-8-6(a)]

The permittee shall conduct NO_x, CO, PM_{10}, and VOC testing on the turbines at the 60% and 100% operating rates, with testing at the 100% turbine load to include testing at both a 70% and 100% duct burner operating rate. NO_x and CO testing shall also be conducted on the turbines at two additional intermediate points in the operating range, pursuant to 40 CFR §60.335(c)(3). 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).

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[4] Added by this administrative amendment dated 04-29-04 in accordance with 252:100-8-7.2(a).

The permittee shall conduct formaldehyde testing on the turbines at the 60% 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 6C	SO_2 emissions From Stationary Sources
Method 8:	Sulfuric Acid Mist.
Method 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
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.

13. NO_X and CO concentrations listed in Specific Condition No.1 shall not be exceeded except during periods of start-up, shutdown or maintenance operations. Such periods shall 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 shall comply with the provisions of OAC 252:100-9 for excess emissions during start-up, shutdown, 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.

14. 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.

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

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

16. No later than 30 days after each anniversary date of the issuance of an operating 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. Quarterly reports as defined in 40 CFR 75.64

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PART 70 PERMIT

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

Issuance Date: ______________________ Permit[5] Number: 2000-090-C (M-4) (PSD)

Redbud Energy, LLC

having complied with the requirements of the law, is hereby granted permission to construct an electric power cogeneration plant located in Sec. 17-17-T14N-R1E, Oklahoma County, Oklahoma,

subject to the following conditions, attached:

[X] Standard Conditions dated October 15, 2003
[X] Specific Conditions

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

______________________________________ Chief Engineer, Air Quality Division

[5] Changed by this administrative amendment dated 04-29-04 in accordance with 252:100-8-7.2(a). Administrative amendments are afforded coverage by the permit shield in 252:100-8-6(d).

Redbud Energy, LP
Attn: Mr. Mark Kadon
20922 North Triple XXX Road
Luther, OK 73054

SUBJECT: Permit Application No. 2000-090-C (M-4) (PSD)
Redbud Cogeneration Plant
Sec. 17 – T14N – R1E
Oklahoma County, Oklahoma

Dear Mr. Kadon:

Enclosed is the **amended permit** authorizing construction of the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions, which are attached. Administrative amendments are afforded coverage by the permit shield in 252:100-8-6(d).

Thank you for your cooperation in this matter. If we may be of further service, please contact our office at (405) 702-4100.

Sincerely,

Doug Meese, P.E.

AIR QUALITY DIVISION
Enclosures