OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **March 23, 2006**

TO:	Dawson Lasseter, P.E., Chief Engineer, Air Quality
THROUGH:	Grover Campbell, P.E., Existing Source Permits Section Phil Martin, P.E., New Source Permits Section
THROUGH:	Peer Review
FROM:	Jian Yue, P.E., Engineering Section
SUBJECT:	Evaluation of Permit Application No. **97-118-C (PSD)** Enogex Products Corporation (Enogex) Wetumka Gas Processing Plant Sec. 29-T8N-R11E, Hughes County Driving Directions: 7 miles south of Wetumka on Hwy 75

SECTION I. INTRODUCTION

Transok Gas Processing, LLC submitted a PSD construction permit on August 20, 2001 for Greasy Creek Processing Plant. The ownership then was changed to Enogex and the facility's name has been changed to Wetumka Gas Processing Plant (SIC 1321). This permit application was required by ODEQ Consent Order No. 01-160, issued on May 22, 2001 to address three 1,100-hp White engines (Nos. 144, 508, and 509) installed in 1984 and one 1,650-hp MEP6GT engine (No. 510) installed in 1985. On December 1, 2005, Enogex submitted another PSD construction permit to install new piping. This modification qualifies as a change of method in operation, therefore, emission increases are based on future potential vs. past actual. Based on this review, PSD significance levels for NOx and CO were exceeded. However, since no physical changes occur at the sources emitting NOx and CO, BACT is not required. New piping will result in negligible VOC emission increases, so the facility's current potential to emit remains the same for all pollutants and this modification will not affect the modeling results done for the first PSD permit application. Therefore, this permit will combine both applications.

This facility is currently operating under Permits No. 97-118-C (M-1), 88-046-O, 85-016-O, 85-004-O, and 83-033-O. A Title V operating permit application was submitted on March 4, 1997 and is pending the issuance of this permit. The Title V operating permit, when issued, will supercede all existing permits for this facility.

SECTION II. FACILITY DESCRIPTION

Wetumka Gas Processing Plant (Facility) is a natural gas gathering facility, liquids extraction facility, and storage field. Natural gas is received at the Facility through suction lines. Free liquids are knocked out by separators and stored in condensate tanks, and gas is routed to the de-ethanizer and de-propanizer where product is removed by cryogenic separation. Liquid product is pumped to a pipeline for transport downstream or pumped to an Enogex truck loading facility near the plant. Thirteen gas-fired engines and three (3) electric-driven compressors are used for boosting gas pressure prior to discharge from the Facility. Additionally, there is one (1) electric-driven compressor that is used in the cryogenic separation process. In addition, there are two glycol dehydrators at the site that are used to remove water from the storage field gas stream prior to discharge from the Facility.

SECTION III. EQUIPMENT

Emission units have been arranged into Emission Unit Groups (EUGs) as outlined below. Emission units that emit the same regulated air pollutants, trigger the same applicable requirements, share the same compliance demonstration methods, and share the same proposed compliance assurance certifications are combined as one EUG.

EUG-1 Rich Burn Engines (Except for E-149)

EU	Point	Description	Size	Serial No.	Construction Date
E-601	P-C1	White 8G825 Engine	800-hp	20769	1973
E-602	P-C2	White 8G825 Engine	800-hp	264399	1973
E-126	P-C3	White 8G825 Engine	800-hp	20700	1973
E-127	P-C4	White 8G825 Engine	800-hp	272589	1973
E-128	P-C5	White 8G825 Engine	800-hp	21062	1973
E-512	P-C6	White 8G825 Engine	800-hp	21061	1978
E-511	P-C7	White 8G825 Engine	800-hp	20859	1978
E-149	P-C14	White 12GTB Engine	2,000-hp	32087	1991

EUG-2 Engines Installed in 1984

EU	Point	Description	Size	Serial #	Const. Date
E-144	P-C8	White 8GTL	1,100-hp	286609	1984
E-508	P-C9	White 8GTL	1,100-hp	287469	1984
E-509	P-C10	White 8GTL	1,100-hp	286579	1984

EUG-3 Engine Installed in 1985

EU	Point	Description	Size	Serial #	Const. Date
E-510	P-C12	MEP 6GT Engine	1,650-hp	82367	1985

EUG-4 Engine Installed in 1985

EU	Point	Description	Size	Serial #	Const. Date
E-603	P-C11	MEP 10GT Engine	2,750-hp	82392	1985

EUG-5 Glycol Dehydrators

EU	Point	Description	Construction Date
E-DEHY2	P-VENT2	West Glycol Dehydrator	1990
E-DEHY3	P-VENT3	Middle Glycol Dehydrator	1990

EUG-6 Flare and Process Heaters

EU	Point	Description	Size (MMBTUH)
E-FLARE	P-FLARE	Emergency Flare	-
E-HTR1	P-HTR1	Process Heater	3.1
E-HTR2	P-HTR2	Process Heater	3.1
E-HTR3	P-HTR3	Dehy2 Reboiler	2.0
E-HTR4	P-HTR4	Dehy3 Reboler	2.0
E-HTR5	P-HTR5	Glycol Reclaimer	0.4

EUG-7 Condensate Tanks

EU	Point	Description	Capacity (gallon)
E-TANK1	P-TANK1	Condensate Tank	16,800
E-TANK2	P-TANK2	Condensate Tank	16,800
E-TANK3	P-TANK3	Condensate Tank	16,800

EUG-8 Storage Tanks

EU	Point	Description	Capacity (gallon)
E-TANK4	P-TANK4	Produced Water	8,400
E-TANK5	P-TANK5	Methanol	8,400
E-TANK6	P-TANK6	Used Oil	4,200
E-TANK7	P-TANK7	Engine Oil	1,000
E-TANK8	P-TANK8	Engine Oil	6,000
E-TANK9	P-TANK9	Engine Oil	1,000
E-TANK10	P-TANK10	Engine Oil	600
E-TANK11	P-TANK11	TEG	6,000
E-TANK12	P-TANK12	Coolant	2,000
E-TANK13	P-TANK13	Produced Water	4,200
E-TANK14	P-TANK14	Used TEG	4,800
E-TANK15	P-TANK15	Used TEG	420
E-TANK16	P-TANK16	Used TEG	420
E-TANK17	P-TANK17	Wash Soap	400
E-TANK18	P-TANK18	Oil/Coolant	205/46
E-TANK19	P-TANK19	Methanol	1,000

EUG-9 Fugitive Components

Component	Components #
Valves	3,570
Pump Seals	40
Flanges	6,300
Relief Valves	100

EUG-10 Facility Wide

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

SECTION IV. HISTORICAL PSD PERMITTING ISSUES (AS IDENTIFIED IN CONSENT ORDER NO. 01-160)

Background

In July of 1984, Transok installed three 1,100-hp White Superior compressor engines under Permit No. 83-033-O, which determined that a PSD permit was not required. However, subsequent review has determined that installations of these engines constituted a "major modification" as defined at OAC 252:100-8-30 *et seq.* and was therefore subject to PSD permitting. In February of 1985, Transok installed a 1,650-hp MEP (Unit 510) under Permit No. 85-004-O, which restricted emissions below PSD significance levels. In June of 1985, Transok applied for a PSD permit (85-016-C) to install a 2,750-hp MEP 10GT engine (Unit 603). Subsequent review has determined that Unit 510 should have been included in the PSD permit for Unit 603 since they can be characterized as one project.

Consent Order No. 01-160 stated that:

(A) Enogex (previously Transok) shall submit a PSD permit application encompassing the three 1,100 HP White Superior compressor engines…… Such permit application shall encompass a Best Available Control Technology (BACT) analysis……

(B) As part of the application referenced in paragraph (A) above, Enogex (previously Transok) shall also seek a permit encompassing MEP Unit 510……

PSD Netting

The Facility was an existing PSD source before the modification in 1984 with both NOx and CO emissions greater than 250 TPY. The following table lists emission increases due to the 1984 modification.

EU	NOx		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1,100-hp White 8GTL Compressor Engine	15.76	69.04	3.15	13.81	2.43	10.62
1,100-hp White 8GTL Compressor Engine	15.76	69.04	3.15	13.81	2.43	10.62
1,100-hp White 8GTL Compressor Engine	15.76	69.04	3.15	13.81	2.43	10.62
Total Increases	47.28	207.12	9.45	41.43	7.29	31.86
PSD Significance Level		40		100		40
PSD Netting Required?		**Yes**		**No**		**No**

The contemporaneous period begins three years prior to construction of the compressor engines, and ends when the engines begin normal operation. Therefore, based on the construction and operation dates, the contemporaneous period for the three White engines began in 1981, and ended in 1984. There were no other modifications at the Wetumka facility during these contemporaneous periods. Therefore, the 1984 modification is subject to PSD review for NOx.

The following table lists emission increases due to the 1985 modification.

EU	NOx		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
1,650-hp MEP 10GT Compressor Engine	9.09	39.83	18.19	79.66	3.64	15.93
2,750-hp MEP 10GT Compressor Engine	24.25	106.22	21.22	92.94	6.06	26.55
Total Increases	33.34	146.05	39.41	172.6	9.7	42.48
PSD Significance Level		40		100		40
PSD Netting Required?		**Yes**		**Yes**		**Yes**

The contemporaneous period for the two MEP engines began in 1982, and ended in 1985. There were no other modifications at the Wetumka facility during these contemporaneous periods other than the 1984 modification addressed above. Therefore, the 1985 modification is subject to PSD review for NOx, CO, and VOC.

SECTION V. CURRENT PSD PERMITTING PROJECT

<u>Project Description</u>

Enogex has identified a need to increase operational flexibility to meet customer demands. Current Facility piping configuration allows natural gas to move through several suction headers and change the direction of flow based on requirements for different types of service (i.e., gathering, storage, processing, or transmission). The piping associated with Line 13 provides for two (2) different suction header routing options, which includes one (1) header for processing and one (1) header for storage or transmission pipeline. Line 13 natural gas is currently considered low-BTU non-processable gas; therefore it is not economical for Enogex to route the gas through the processing header. As a result, the Line 13 gas is currently being routed through the storage/transmission header and measured through a 6” meter tube. Based on current volumes, this header system is not efficient due to the line being equipped with 4” valves causing a significant pressure drop prior to compression. As a result of this significant pressure drop and demand to move existing gas volumes, the Facility must operate additional compression which increases actual emissions. Further, the changing needs of customers and increased drilling activity has resulted in an increase of Line 13 gas which exceeds the design criteria for the existing 6” meter tube and restricts the volume of gas. This restriction limits the ability to properly measure the gas volume through the meter.

There are two (2) phases to the proposed project which is reviewed as a single project for permitting purpose, however for budgeting purposes they are considered two (2) separate projects. Both projects will involve piping modifications to increase operational flexibility at the Facility. A summary of the projects are as follows.

> **Line 13 Project:** Enogex proposes to install new piping where Line 13 enters the Facility to connect to the existing storage/transmission suction header. The new piping will include a 12” meter tube to allow for proper measurement of existing and future gas volumes. Further, the properly sized meter tube and absence of 4” valves will eliminate the current pressure drop issues for compression. With this proposed change, Enogex anticipates the operation of fewer compressor engines to move the current gas volumes

today. This will allow for better utilization of existing horsepower, economical fuel savings and a potential reduction in actual emissions based on current gas volumes. As a part of this project, specific piping segments will be removed from service.

Unit's #604 & #605 Separation Project: Enogex also proposes to install a new valve downstream of the proposed Line 13 meter tube (i.e., 12" meter tube) to provide for a future connection to the suction header of the electric units (i.e., Unit's #604 & #605). The electric units were originally designed and installed to be in storage or low-pressure service. Current piping configuration requires that both units be in the same service when operating. In other words, if one unit is operating in storage service, the remaining unit can only operate in the same service. The proposed piping modifications will allow Enogex to route Line 13 gas into the low pressure header and utilize one (1) or both of the electric units for compression.

Emission Increases Based on Future Potential vs. Past Actual

Enogex chose actual operating hours in 2003 and 2004 to calculate actual emissions.

Emission Unit	Averaging Operating Hours for 2003&2004	Potential to Emit			Actual Emissions		
		NOx TPY	CO TPY	VOC TPY	NOx TPY	CO TPY	VOC TPY
E-601	3,720	18.53	18.53	1.00	7.87	7.87	0.42
E-602	3,707	18.53	18.53	1.00	7.84	7.84	0.42
E-126	6,685.5	18.53	18.53	1.00	14.14	14.14	0.76
E-127	6,605.5	18.53	18.53	1.00	13.97	13.97	0.75
E-128	4,940.5	139.07	123.29	2.7	78.43	69.53	1.52
E-511	2,594	18.53	18.53	1.00	5.49	5.49	0.3
E-512	3,723	18.53	18.53	1.00	7.88	7.88	0.43
E-144	3,534	69.04	13.81	10.62	27.85	5.57	4.28
E-508	7,581	69.04	13.81	10.62	59.75	11.95	9.19
E-509	8,532.5	69.04	13.81	10.62	67.25	13.45	10.34
E-510	5,998.5	39.83	79.66	15.93	27.27	54.55	10.91
E-603	8,601	106.22	92.94	26.55	104.29	91.25	26.07
E-149	2,780	38.62	57.94	11.59	12.26	18.39	3.68
Total		**642.04**	**506.44**	**94.63**	**434.29**	**321.88**	**69.07**

Emission increases are listed in the following table:

Emission Increases Based on Future Potential vs. Past Actual		
NOx TPY	**CO TPY**	**VOC TPY**
207.75	184.56	25.56

The small number of valves, flanges, and other connections that will be added will be offset by a similar number of components that will be removed. The total VOC added impact is conservatively estimated to be less than 0.5 TPY since the piping will mostly be underground and since the gas is lean with a VOC content less than 5% by weight.

NOx and CO emissions increase exceed their PSD significance levels. There are no other emission increases or decreases in the past three year contemporaneous period. Therefore, this project will be subject to PSD review. However, since no physical changes occur for sources emitting NOx and CO, BACT is not required. The construction and installation of the piping components will be in accordance with industry standards and applicable components will be included in the LDAR program.

New piping will result in negligible VOC emission increases, so the facility's current potential to emit remain the same for all pollutants. Therefore, this modification will not affect the modeling results done for the historic PSD permit application.

The BACT, Air Quality Impacts, NAAQS Modeling, and Additional Impacts Analysis sections of this permit memorandum does not include any discussions associated with the newly proposed project. Since the historical PSD issues are addressed in this PSD Review and are based on potential emissions and corresponding emission limits as specified in this permit, no further analysis is required for the Line 13 and Unit's #604 & #605 projects.

SECTION VI. EMISSIONS

The applicant took the following steps in order to comply with NAAQS and PSD increment requirements:

1). Raise stacks on engines 601, 602, 126, and 127 to 20 feet.
2). Raise stacks on engines 128, 511, 512, and 144 to 25 feet.
3). Replace engine 517 with an electric compressor.
4). Install catalytic converters on engines 126, 127, 601, 602, 511, and 512 to reduce NOx emissions to 2.4 g/hp-hr.

Engine emissions are based on emission factors listed below. Tank emissions are based on TANKS 4 program. Flash emissions were calculated using the WINSIM process simulation method and is combined with the tank breathing and working emissions. Formaldehyde emissions are based on AP-42 (7/00), Chapter 3.2, Table 3.2-2 for 4-stroke lean-burn engines and Table 3.2-3 for 4-stroke rich-burn engines, and Table 3.2-1 for 2-stroke lean burn engines. A control efficiency of 70 % was used for catalytic converters.

Facility Wide Total Emissions

EU	NOx		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
E-601	4.23	18.53	4.23	18.53	0.23	1.00
E-602	4.23	18.53	4.23	18.53	0.23	1.00
E-126	4.23	18.53	4.23	18.53	0.23	1.00
E-127	4.23	18.53	4.23	18.53	0.23	1.00
E-128	31.75	139.07	28.15	123.29	0.62	2.7
E-511	4.23	18.53	4.23	18.53	0.23	1.00
E-512	4.23	18.53	4.23	18.53	0.23	1.00
E-144*	15.76	69.04	3.15	13.81	2.43	10.62
E-508*	15.76	69.04	3.15	13.81	2.43	10.62
E-509*	15.76	69.04	3.15	13.81	2.43	10.62
E-510*	9.09	39.83	18.19	79.66	3.64	15.93
E-603	24.25	106.22	21.22	92.94	6.06	26.55
E-149	8.82	38.62	13.23	57.94	2.65	11.59
DEHY2 (Still Vent)	-	-	-	-	2.72	11.91
DEHY2 (Reboiler)	0.20	0.86	0.16	0.72	0.01	0.05
DEHY3 (Still Vent)	-	-	-	-	2.72	11.91
DEHY3 (Reboiler)	0.20	0.86	0.16	0.72	0.01	0.05
Glycol Reclaimer	0.04	0.17	0.03	0.14	0.01	0.01
HTR1	0.30	1.33	0.26	1.12	0.02	0.07
HTR2	0.30	1.33	0.26	1.12	0.02	0.07
TANK1** TANK2** TANK3**	-	-	-	-	-	283.71
LOAD	-	-	-	-	-	2.0
FUGITIVES	-	-	-	-	9.03	39.57
FLARE	0.007	0.029	0.036	0.158	0.001	0.006
Totals	**147.62**	**646.63**	**116.53**	**510.42**	**36.18**	**444.03**

*Sources undergoing this PSD review.

**Emissions include flash emissions.

Engine Emission Factors

Engines	Type	Fuel Use (MMBTUH)	NOx (g/hp-hr)	CO (g/hp-hr)	VOC (g/hp-hr)	Formaldehyde (lb/MMBtu)
E-601	4-Cycle Rich Burn	6.2	2.4	2.4	0.13	6.15E-03
E-602		6.2	2.4	2.4	0.13	6.15E-03
E-126		6.2	2.4	2.4	0.13	6.15E-03
E-127		6.2	2.4	2.4	0.13	6.15E-03
E-128		6.2	18.0	15.96	0.35	2.05E-02
E-511		6.2	2.4	2.4	0.13	6.15E-03
E-512		6.2	2.4	2.4	0.13	6.15E-03
E-144	4-Cycle Lean Burn	8.14	6.5	1.3	1	5.28E-02
E-508		8.14	6.5	1.3	1	5.28E-02
E-509		8.14	6.5	1.3	1	5.28E-02
E-510	2-Cycle Lean Burn	12.89	2.5	5	1	5.52E-02
E-603		21.48	4	3.5	1	5.52E-02
E-149	4-Cycle Lean Burn	14.3	2.0	3.0	0.6	5.28E-02

Brake-specific fuel consumption, stack dimensions, and the air emissions for engines are listed in the following table. Moisture contents of stack gases have been estimated from the stoichiometric ratio of two cubic feet of water per cubic foot of methane fuel.

Engine Specific Stack Parameters

Parameter	E-144	E-508 & E509	E-510	E-149	White 8G825[1]	E-603
Stack Diameter (ft)	1.00	0.83	1.50	1.33	0.83	1.50
Stack Height (ft)	25.0	30.0	36.0	20.0	20.0	48.0
Horse Power (hp)	1,100	1,100	1,650	2,000	800	2,750
Fuel Consumption (SCFH)*	8,140	8,140	12,210	14,300	6,200	20,600
Fuel Consumption (BTU/hp-hr)	7,400	7,400	7,400	7,150	7,750	7,491
Exhaust Rate (ACFM)	6,010	6,010	12,365	11,505	4,427	16,000
Exhaust Temperature (°F)	920	920	650	770	1,340	700
Moisture Content (%)	12	12	7	10	16	9

* Calculated assuming 1,000 BTU/SCF.

[1] - White 8G825 includes engines E-601, E-602, E-126, E-127, E-128, E-512, and E-511.

Formaldehyde Emissions

EU	Formaldehyde	
	lb/hr	**TPY**
E-601	0.04	0.17
E-602	0.04	0.17
E-126	0.04	0.17
E-127	0.04	0.17
E-128	0.13	0.56
E-511	0.04	0.17
E-512	0.04	0.17
E-144*	0.43	1.88
E-508*	0.43	1.88
E-509*	0.43	1.88
E-510*	0.71	3.12
E-603	1.19	5.19
E-149	0.76	3.31
Total	**4.32**	**18.84**

* Sources undergoing this PSD review.

The dehydration units use triethylene glycol desiccants and emit benzene, toluene, ethyl benzene, xylene, and n-hexane from the regenerator vents. The emission levels were estimated using rich/lean analysis with a maximum glycol circulation rate of 14 gallons/min and a maximum gas flow rate of 250 MMSCFD (maximum dehydrator processing capability) per unit, 80% control efficiency for the condensor, and a safety factor of 4. Emissions were also estimated using GRI-GlyCalc ARL which resulted in numbers much lower than emissions listed in the following table.

EMISSIONS OF HAPs

TOXICS	CAS NUMBER	EMISSIONS	
		lb/hr	**TPY**
Benzene	71-43-2	0.21	0.907
Toluene	108-88-3	0.75	3.285
Ethyl benzene	95-47-6	0.08	0.35
Xylene	108-38-3	0.63	2.746
n-Hexane	110-54-3	0.06	0.282
TOTAL		**1.73**	**7.57**

SECTION VII. PSD REVIEW

Engines 144, 508, 509, and 510 have been reviewed for all applicable air pollution control rules and regulations including Prevention of Significant Deterioration. Full PSD review of emissions consists of the following:

- determination of best available control technology (BACT);
- evaluation of existing air quality and determination of monitoring requirements;
- evaluation of PSD increment consumption;

- analysis of compliance with National Ambient Air Quality Standards (NAAQS);
- evaluation of source-related impacts on growth, soils, vegetation, visibility;
- and evaluation of Class I area impacts.

Best Available Control Technology

A. 1984 Modification

BACT analysis is required for NOx. The applicant performed a historic BACT analysis based on technologies available during the time period in which the engines were installed at the site, using EPA's "top-down" approach described in the *New Source Review Workshop Manual* (10/1990). The top-down approach allows selection of the best control technology among those available, when taking into account energy, environmental, and economic impacts. The cost and control technology review is based on the EPA guidance document Alternative Control Techniques (ACT) NOx emissions from Stationary Internal Combustion Engines (EPA-453/R-93-032).

1. Identify All Available Control Technologies

The following table lists control technologies selected as potential historical BACT candidates.

Control Technology[a, d]	**Control Efficiency (%)**	**In Service On**			**Technically Feasible on Lean Burn Engines?**
		IC Lean Burn Engines	**IC Rich Burn Engines**	**Other Combustion Sources**	
Selective Catalytic Reduction (SCR)	40-90	Yes	No	Yes	Yes
Turbo, Lean AF/IR[b]	64	Yes	Yes	Yes	Yes
Turbo, Lean AF/IR[c]	60	Yes	Yes	Yes	Yes
Non-Selective Catalytic Reduction (NSCR)	20-50	No	Yes	Yes	No

[a] Ranked in order of highest to lowest stringency
[b] Based on data provided by manufacturer for 100 °F air manifold temperature
[c] Based on data provided by manufacturer for 130 °F air manifold temperature
[d] Non-Selective Catalytic Reduction is not considered efficient for lean burn engines due to the ingerently high exhaust oxygen content reducing the catalyst performance, therefore it is not a viable alternative.

2. Technical Feasibility Considerations

The subject engines were turbocharged and equipped with lean operation AF/IR designed to achive an emission level that was considered to be low NOx emissions technology during that time period (1984).

Non-Selective catalytic reduction (NSCR) was eliminated as technically feasible because the technology required much lower oxygen content in the exhaust stream to be effective for NOx control.

Selective catalytic reduction (SCR) was evaluated and considered to be a technically feasible control. However, this SCR technology could only be applied under a constant engine load condition, which is very difficult to maintain and would cause operational problems. Also, the use of this technology, which included ammonia injection, had the potential to introduce an additional toxic into the environment.

3. Evaluate Most Effective Controls

In the feasible technologies, SCR is the highest ranking control option. The feasibility analysis is based on the lowest reported achievable level for SCR with a NOx removal efficiency of 90 percent.

The next most stringent level that is achievable would be turbo charging and installing lean operation Air-to-Fuel ratio controllers along with Ignition Retard (IR) timing capability.

4. Cost Effectiveness and Environmental Impact Analysis

Cost effectiveness over baseline has been estimated as $1,368/ton and incremental cost effectiveness has been estimated as $4,305/ton. This is not considered to be in the acceptable range of NOx control costs for similar sources during the time period when the engines were installed (1984). In addition, SCR controls have a potential byproduct of ammonia. Another environmental impact is the spent catalyst, which would have to be disposed of at certain operating intervals. Disposal of this waste would create an additional economic and environmental burden.

5. Accepted BACT

Based on the analysis above, it is determined that turbo charged, AF/IR controls while maintaining an air manifold inlet temperature of approximately 130 °F, along with controls added to other sources at this site as listed below satisfy the BACT requirements:

1). Raise stacks on engines 601, 602, 126, and 127 to 20 feet.
2). Raise stacks on engines 128, 511, 512, and 144 to 25 feet.
3). Replace engine 517 with an electric compressor.
4). Install catalytic converters on engines 126, 127, 601, 602, 511, and 512 to reduce NOx and CO emissions to 2.4 g/hp-hr.

B. 1985 Modification

Unit #603 was installed during the same timeframe as Unit #510 and they are very similar engines. Unit #603 went through PSD review which states that the use of clean-burn design and air-fuel ratio control is acceptable as BACT for NOx emissions from the engine. The manufacturer (BFGoodrich) also stated that these two engines were installed with the best available technology at the time. The engines were installed with the then current pneumatic air fuel ratio controls, mechanical fuel valves, and state of the art ignition systems. As a result, Units # 510 and 603 are considered to satisfy BACT requirements for NOx, CO, and VOC as configured and no further controls are required.

AIR QUALITY IMPACTS

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

A. Significant Impact Determination

1. Description of Air Quality Dispersion Models

The air quality modeling analyses employed USEPA's Industrial Source Complex (ISCST3) model (USEPA, 2002). The ISCST3 model is recommended as a guideline model for assessing the impact of aerodynamic downwash in 40 CFR 51 Appendix W, Guideline on Air Quality Models. The regulatory default options were selected such that USEPA guideline requirements were met.

2. Plume Downwash

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.

3. Meteorological Data

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 6.1 meters.

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 gas 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 facility is not comprised of greater than 50 percent of the above land use types.

4. Receptor Grid

The receptor grid for the ISC3 dispersion model was designed to identify the maximum air quality impact due to the proposed modifications at the Wetumka Gas Processing 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 1000 meter spaced coarse grid receptors. All receptors were modeled with 7.5 minute terrain data produced by the United States Geological Survey (USGS). The coordinates were derived from the NAD 27 State Plane Coordinate System. All quadrangles used to develop the gridded terrain data within the radius of impact for the proposed facility were based on the NAD 27 system.

5. Significance Analysis

Modeling was conducted to determine if the NO_2 impacts from the project exceeded the modeling significance levels. The highest modeled pollutant concentration for the averaging time was used to determine whether the source would have a significant ambient impact for NO_2.

Significance Level Comparison

Pollutant	Averaging Period	Year	Max. Concentration $\mu g/m^3$	Significance Level $\mu g/m^3$
NO_2	Annual	1986	7	1

The modeling indicates facility emissions will result in ambient concentrations above the significance level in which an area of impact (AOI) is defined for NO_2. Therefore, additional modeling for PSD increment and NAAQS compliance was required for NO_2. The AOI, a circular area with a radius extending from the project's center to the most distant receptor where a significant impact is predicted, was determined to extend 2.5 km from the center of the facility.

B. NAAQS Modeling Analysis

The full impact analysis to demonstrate compliance with the NAAQS expanded the significance analysis to include existing sources as well as new sources within a 50-km radius of the AOI determined in the significance analysis. The emission rates for modeled sources for the full impact analysis were based on the maximum short term potential emissions.

In order to eliminate sources with minimal affect on the AOI, a screening procedure known as the "20D Rule" was applied to the sources on the emission inventory from Oklahoma. This is a screening procedure designed to reduce the number of insignificant modeled sources. The rule is applied by multiplying the distance from the sources (in kilometers) by 20. If the result is greater than the emission rate (in tons per year), the source is eliminated. If the result is less than the emission rate the source is included in the NAAQS analysis. Based on this procedure all background sources except for the PSO Weleetka Power Station, OG&E Seminole Power Station, Kiowa Tenaska Kiamichi Power Station, Anchor Glasss Henryetta Facility were eliminated from the NAAQS and Increment analysis. The following table lists the background sources and parameters used in the NAAQS modeling analysis.

NAAQS Source Parameters

Source	Easting	Northing	Elevation	Stack Height	Temp.	Velocity	Stack Diameter	NO_X Modeled
EU	**Meters**	**Meters**	**Meters**	**Feet**	**°F**	**Ft/Sec**	**Feet**	**lb/hr**
Wetumka Gas Plant								
601	758141	3891905	294	20.0	1,340	135.3	0.83	4.23
602	758132	3891905	294	20.0	1,340	135.3	0.83	4.23
126	758124	3891905	294	20.0	1,340	135.3	0.83	4.23
127	758116	3891905	294	20.0	1,340	135.3	0.83	4.23
128	758107	3891905	294	25.0	1,340	135.3	0.83	31.75
512	758075	3891904	294	25.0	1,340	135.3	0.83	4.23
511	758070	3891904	294	25.0	1,340	135.3	0.83	4.23
144	758091	3891895	294	25.0	920	127.5	1.17	15.76
508	758060	3891906	294	30.0	920	183.7	0.83	15.76
509	758042	3891906	294	30.0	920	183.7	0.83	15.76
510	758100	3891895	294	36.0	650	116.6	1.50	9.09
603	758168	3891889	294	48.0	700	194.3	1.50	24.25
149	758083	3891904	294	20.0	770	137.3	1.33	8.82
RBLR2	758133	3891839	294	28.5	317	11.8	1.33	0.19
RBLR3	758137	3891839	294	26.6	363	11.8	1.00	0.19

Source	Easting	Northing	Elevation	Stack Height	Temp.	Velocity	Stack Diameter	NO_X Modeled
EU	Meters	Meters	Meters	Feet	°F	Ft/Sec	Feet	lb/hr
HTR1	758008	3891861	294	34.0	348	18.2	1.33	0.30
HTR2	758011	3891861	294	34.0	334	18.2	1.33	0.30
FLARE	757975	3891865	294	56.0	1,831	66.0	0.02	0.007
Background Sources								
PSO Weleetka Power Plant								
Unit 4	760365	3912822	207.3	54.0	900	93.3	10.20	754.9
Unit 5	760365	3912822	207.3	54.0	900	93.3	10.20	754.9
Unit 6	760365	3912822	207.3	54.0	900	93.3	10.20	754.9
Anchor Glass Henrietta Facility								
Furnace 1	775064	3926929	202.4	85.0	800	23.0	7.50	161.2
Furnace 2	775064	3926929	202.4	75.0	400	31.0	7.50	97.8
Kiowa Power Tenaska Kiamichi Power Plant								
CTGDB1	780816	3841839	213.4	165.0	206	9.0	18.90	227.8
CTGDB2	780816	3841839	213.4	165.0	206	9.0	18.90	227.8
OGE Seminole Power Plant								
Unit 1	707667	3871436	289.6	178.0	247	45.0	15.00	168.7
Unit 2	707667	3871436	289.6	178.0	247	45.0	15.00	148.6
Unit 3	707667	3871436	289.6	350.0	282	65.0	18.00	269.2

The 2004 annual mean NO_2 data from all of the monitors in Oklahoma is shown in the table below.

2004 Annual Mean NO_2 Ambient Monitoring Data for Oklahoma

Monitor ID	City	County	Observations	Concentration $\mu g/m^3$
400719003	Ponca City	Kay	5,587	9
400979014	Pryor	Mayes	4,096	9
401431127	Tulsa	Tulsa	8,581	9
400219002	Tahlequah	Cherokee	8,163	13
401159004	Miami	Ottawa	8,194	13
401091037	Oklahoma City	Oklahoma	8,639	15
401090033	Oklahoma City	Oklahoma	8,733	21

The modeled NO_2 annual concentration was analyzed for compliance with the NAAQS. The applicant has demonstrated compliance through the application of the ambient ratio method (ARM). A NO_2/NO_X ratio of 0.75 as allowed in the "Guideline on Air Quality Models" was multiplied by the modeled impacts to determine the actual impacts. Based on the monitoring data above, a NO_2 concentration of 9 $\mu g/m^3$ was determined as representative of a rural background NO_2 concentration and was used in the NAAQS analysis to calculate the impacts from the analysis.

NAAQS Modeled and Monitored Results

	Location		Concentrations				
	Easting	Northing	Modeled	ARM Impact	Background	Total	Stand.
Year	Meters	Meters	µg/m³	µg/m³	µg/m³	µg/m³	µg/m³
1986	758091	3892109	109	81	9	90	100
1987	758091	3892109	93	70	9	79	100
1988	758091	3892109	97	73	9	82	100
1990	758091	3892109	121	90	9	99	100
1991	758091	3892109	103	77	9	86	100

C. Increment Consumption Evaluation

Increment consumption is a measure of deterioration in an area after an effective date. The major source baseline date for nitrogen dioxide was February 8, 1988. All increases and decreases occurring at existing PSD major facilities after this baseline date are counted against a maximum increase of 25 µg/m³.

Hughes County is a part of Air Quality Control Region 188 as designated under 40 CFR 81.337. The minor source baseline date for this area was set on July 30, 1990 by the submission of a complete application for the PSD modification of the Maysville Gas Plant in Garvin County, permit number 85-037-C (M-1). After this date, all increases and decreases occurring at both PSD major and minor facilities are counted against the maximum increase of 25 µg/m³.

Even though increases incurred through the addition of some of the engines prior to the major source baseline date, emissions from those engines are evaluated against the increment because the facility did not receive a PSD permit for the addition of those engines. First, all increment consuming sources were modeled to determine the amount of increment consumed. Since the increases from the current project and other sources exceeded the allowable increment, creditable reductions from the facility were then incorporated into the analysis. The reductions due to engines 601, 602, 126, 127, 511, and 512 being retrofitted with catalytic converters was included in the analysis along with the removal of engine 106 in 1991, which was installed in 1974. Increases in stack height for engines 601, 602, 126, 127, 128, 511, and 512 were not included in the analysis. Removal of engine 517 was not included since it was replaced with an electric motor as part of this project and the engine was installed as part of the original project. Baseline emissions from the facility were obtained from the 1988 annual emission inventories and were calculated using the reported tons per year and the reported operating factor (hours/year). The following table of stack parameters and emission rates were used in the evaluation of increment consumption.

Increment Consumption Source Parameters

Source	Easting	Northing	Elevation	Stack Height	Temp.	Velocity	Stack Dia.	1988	New	Modeled
EU	Meters	Meters	Meters	Feet	°F	Feet/Sec	Feet	lb/hr	lb/hr	lb/hr
II. Wetumka Gas Plant										
601	758141	3891905	294	20.0	1,340	135.3	0.83	9.46	4.23	-5.23
602	758132	3891905	294	20.0	1,340	135.3	0.83	9.91	4.23	-5.68
126	758124	3891905	294	20.0	1,340	135.3	0.83	8.24	4.23	-4.01
127	758116	3891905	294	20.0	1,340	135.3	0.83	10.65	4.23	-6.42
128	758107	3891905	294	25.0	1,340	135.3	0.83	10.82	31.75	20.93
512	758075	3891904	294	25.0	1,340	135.3	0.83	9.64	4.23	-5.41
511	758070	3891904	294	25.0	1,340	135.3	0.83	6.40	4.23	-2.17
144	758091	3891895	294	25.0	920	127.5	1.17	0.00	15.76	15.76
508	758060	3891906	294	30.0	920	183.7	0.83	0.00	15.76	15.76
509	758042	3891906	294	30.0	920	183.7	0.83	0.00	15.76	15.76
510	758100	3891895	294	36.0	650	116.6	1.50	0.00	9.09	9.09
603	758168	3891889	294	48.0	700	194.30	1.50	22.81	24.25	1.44
149	758083	3891904	294	20.0	770	137.3	1.33	0.00	8.82	8.82
106	758083	3891904	294	10.0	1,009	121.4	0.80	12.10	0.00	-12.10
RBLR1	758141	3891839	294	28.2	700	11.8	0.16	0.08	0.00	-0.08
RBLR2	758133	3891839	294	28.5	317	11.8	1.33	0.00	0.19	0.19
RBLR3	758137	3891839	294	26.6	363	11.8	1.00	0.00	0.19	0.19
HTR1	758008	3891861	294	34.0	348.	18.2	1.33	0.20	0.30	0.09
HTR2	758011	3891861	294	34.0	334	18.2	1.33	0.20	0.30	0.09
FLARE	757975	3891865	294	56.0	1,831	66.0	0.02	0.00	0.01	0.01
III. Background Sources										
Anchor Glass Henrietta Facility										
Furnace 2	760365	3912822	202.4	75.0	400	31.0	7.50	0.00	84.50	84.50
Kiowa Power Tenaska Kiamichi Power Plant										
CTGDB1	760365	3912822	213.4	165.0	206	9.0	18.90	0.00	108.90	108.90
CTGDB2	760365	3912822	213.4	165.0	206	9.0	18.90	0.00	106.80	106.80

The following table presents the results of the increment analysis.

Increment Consumption Model Results

Year	Easting	Northing	Modeled Concentration	Standard
	Meters	Meters	$\mu g/m^3$	$\mu g/m^3$
1986	758091	3891409	22	25
1987	758091	3891409	22	25
1988	758091	3891409	20	25
1990	757991	3892209	20	25
1991	758091	3891409	20	25

D. 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 level for NO_2.

Comparison of Modeled Impact to Monitoring Exemption Level

	Monitoring Exemption Level		Ambient Impact
Pollutant	**Averaging Time**	**μg/m³**	**μg/m³**
NO_2	Annual	14	7

E. Current Project

1. Significance Analysis

Modeling was conducted to determine if the CO and NO_2 emission increases from the current project exceeded the modeling significance levels. The emission increases were based on the PTE minus the two year average emissions from the 2003-2004 emission inventories. The highest modeled pollutant concentration for the averaging time was used to determine whether the source would have a significant ambient impact.

Significance Level Comparison

Pollutant	Averaging Period	Year	Max. Concentration μg/m³	Significance Level μg/m³
NO_2	Annual	1990	48	1
CO	1-hour	1987	2,708	2,000
CO	8-hour	1988	1,491	500

The modeling indicates that the increase in facility emissions from the current project result in ambient concentrations above the significance level for CO and NO_2. However, additional modeling for compliance with the NO_2 increment and NAAQS are not required since there were no increases in the facility's PTE and subsequently no additional increment consumed. Also, since there are no increments established for the 1-hour and 8-hour standard no increment analysis is required for CO. The AOI for the 1-hour and 8-hour CO standards was determined to extend out to 0.1 and 0.2 km from the center of the facility, respectively. Modeling of compliance with the CO NAAQS was required.

2. CO NAAQS Modeling Analysis

The full impact analysis to demonstrate compliance with the NAAQS expanded the significance analysis to include existing sources as well as new sources within a 50-km radius of the AOI determined in the significance analysis. The emission rates for modeled sources for the full impact analysis were based on the maximum short term potential emissions. Again the "20 D Rule" was applied. Based on this procedure all background sources except for the PSO Weleetka Power Station were eliminated from the NAAQS analysis. The following table lists the sources and parameters used in the CO NAAQS modeling analysis.

NAAQS Source Parameters

Source	Easting	Northing	Elevation	Stack Height	Temp.	Velocity	Stack Diameter	CO Modeled
EU	**Meters**	**Meters**	**Meters**	**Feet**	**°F**	**Ft/Sec**	**Feet**	**lb/hr**
Wetumka Gas Plant								
601	758141	3891905	294	20.0	1,340	135.3	0.83	4.23
602	758132	3891905	294	20.0	1,340	135.3	0.83	4.23
126	758124	3891905	294	20.0	1,340	135.3	0.83	4.23
127	758116	3891905	294	20.0	1,340	135.3	0.83	4.23
128	758107	3891905	294	25.0	1,340	135.3	0.83	28.15
512	758075	3891904	294	25.0	1,340	135.3	0.83	4.23
511	758070	3891904	294	25.0	1,340	135.3	0.83	4.23
144	758091	3891895	294	25.0	920	127.5	1.17	3.15
508	758060	3891906	294	30.0	920	183.7	0.83	3.15
509	758042	3891906	294	30.0	920	183.7	0.83	3.15
510	758100	3891895	294	36.0	650	116.6	1.50	18.19
603	758168	3891889	294	48.0	700	194.3	1.50	21.22
149	758083	3891904	294	20.0	770	137.3	1.33	13.23
RBLR2	758133	3891839	294	28.5	317	11.8	1.33	0.16
RBLR3	758137	3891839	294	26.6	363	11.8	1.00	0.16
HTR1	758008	3891861	294	34.0	348	18.2	1.33	0.26
HTR2	758011	3891861	294	34.0	334	18.2	1.33	0.26
FLARE	757975	3891865	294	56.0	1,831	66.0	0.02	0.04
Background Sources								
PSO Weleetka Power Plant								
Unit 4	760365	3912822	207.3	54.0	900	93.3	10.20	118.97
Unit 5	760365	3912822	207.3	54.0	900	93.3	10.20	118.97
Unit 6	760365	3912822	207.3	54.0	900	93.3	10.20	118.97

The 2004 1-hour and 8-hour highest second high (H2H) CO data from all of the monitors in Oklahoma is shown in the table below.

2004 1-hour and 8-hour H2H CO Ambient Monitoring Data for Oklahoma

Monitor ID	City	County	Observations	1-hour $\mu g/m^3$	8-hour $\mu g/m^3$
400219002	Tahlequah	Cherokee	8,632	1,260	458
400310647	Lawton	Comanche	8,592	1,374	1,145
400719003	Ponca City	Kay	5,880	3,550	2,176
400719010	Newkirk	Kay	8,448	802	344
401090047	Oklahoma City	Oklahoma	8,430	3,893	2,519
401159004	Miami	Ottawa	8,369	1,145	573
401430191	Tulsa	Tulsa	8,508	2,977	1,947

The modeled CO 1-hour and 8-hour concentrations were analyzed for compliance with the NAAQS. The maximum CO concentration from the monitoring data above was used in the NAAQS analysis to calculate the impacts from the analysis.

CO NAAQS Analysis Results

Standard		Location		Concentrations			
		Easting	Northing	Modeled	Background	Total	Stand.
	Year	Meters	Meters	$\mu g/m^3$	$\mu g/m^3$	$\mu g/m^3$	$\mu g/m^3$
1-hour	1986	758170	3891919	6,031	3,893	9,924	40,000
	1987	758170	3891919	5,931	3,893	9,824	40,000
	1988	758170	3891919	5,945	3,893	9,838	40,000
	1990	758170	3891919	5,928	3,893	9,821	40,000
	1991	758170	3891919	5,981	3,893	9,874	40,000
8-hour	1986	758170	3891919	2,123	2,519	4,642	10,000
	1987	758185	3891885	2,772	2,519	5,291	10,000
	1988	758183	3891893	2,501	2,519	5,020	10,000
	1990	758183	3891893	1,769	2,519	4,288	10,000
	1991	758170	3891919	2,011	2,519	4,530	10,000

3. Ambient Monitoring

The modeled ground-level concentrations of CO and NO_2 demonstrate that the ambient impacts of the facility are above the monitoring exemption levels.

Comparison of Modeled Impact to Monitoring Exemption Level

	Monitoring Exemption Level		Ambient Impact
Pollutant	Averaging Time	$\mu g/m^3$	$\mu g/m^3$
NO_2	Annual	14	48
CO	1-hour	500	2,708

The Clean Air Act requires that continuous preconstruction air quality monitoring data must be collected to determine whether emissions from a source will result in an exceedance of the National Ambient Air Quality Standards (NAAQS). The basic objective of PSD monitoring is to determine the effect emissions from a source are having or may have on the air quality in any area that may be affected by the emission. The principal use of the data is to establish background air quality concentrations in the vicinity of the proposed source or modification. These background levels are important in determining whether the air quality before or after construction are or will be approaching or exceeding the NAAQS or PSD increment. The previous NAAQS and increment demonstrations for NO_2 were based on the facility's potential to emit. There have been no increases in the potential to emit. Accordingly, preconstruction monitoring serves no function in an evaluation where there are no increases in the allowable emission and no further evaluation will be conducted.

In accordance with the Ambient Monitoring Guidelines for Prevention of Significant Deterioration, EPA-450/4-87-007, existing monitoring data can be used to meet the requirement for preconstruction monitoring. The guidance document discusses the evaluation of the impact of primary pollutants and gives clear guidance for use of a regional monitoring site in instances where the area is generally free from the impact of other point and area sources associated with human activities.

The facility in question is located in a rural area devoid of industry. The maximum impacts from the facility for all pollutants occur within the first 200 meters of the fence line. Thereafter, concentrations drop precipitously resulting in a significant impact radius for the facility that does not extend beyond 200 meters for CO. Background source facilities explicitly modeled play little to no part in the maximum concentrations. As the modeling domain is characterized by flat terrain, all guidance for the use of a regional scale monitor is met. The monitoring site chosen should be and is similar in nature to the impact area.

Further, monitoring for CO and NO_2 will not be required based on the NAAQS compliance demonstration, the use of a representative NO_2 rural background concentration, a maximum CO monitored concentration, and no increase in PTE at the facility as a result of the project. Estimated emission increases are the result of associated emission units. The associated unit operations will not be affected by the proposed change. Additionally, historical/current monitored levels of CO and NO_2 have shown no areas of concern for these pollutants.

F. ADDITIONAL IMPACTS ANALYSIS

1. 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 are needed. The fuel for the plant arrives by pipeline rather than by vehicle.

2. Growth Impacts

The Wetumka Gas Plant employs less than 25 permanent employees, no significant air quality impact is expected. No significant industrial or commercial secondary growth has or will occur as a result of the project since the facility employs less than 25. Most labor, material, and service requirements are already in place.

3. 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 NO_X. NO_X was selected for review since it has been shown to be capable of causing damage to vegetation at elevated ambient concentrations.

To evaluate the potential effects of air pollution on vegetation, Heck and Brandt (1977) recommend the use of a dose analysis. In their summary they presented data collected by several investigators on the growth response of plants to various concentrations and durations. While they qualify this data as being preliminary and not having been subject to rigorous experimentation, they can be applied in this project review. They further caution that the data should only be applied to exposures of periods no longer than 10 to 12 hours. The following table presents data from Heck and Brandt's survey on the potential for plant injury form air pollution.

Concentration (ppm) Producing 5% Injury to Sensitive Vegetation During Short Term Exposure				
Pollutant	**Time (hrs)**	**Sensitive**	**Intermediate**	**Resistant**
Nitrogen Dioxide	0.5	6.0-12	1-25	20
	1.0	3.0-10	9.0-20	18
	2.0	2.5-7.5	7.0-15	13
	4.0	2.6-6.0	5.0-12	10
	8.0	1.5-5.0	4.0-9.0	8

Source: Heck and Brandt, 1977.

The division of plants into sensitive, intermediate and resistant species is somewhat subjective and varies according to the literature reviewed. However, this table can be used as a general guide on the potential effects of the project. The concentrations presented on the table are those that can produce acute changes or injury (i.e., leaf drop and leaf discoloration) in plants exposed to air pollutants from 0.5 to 8.0 hours.

The lower concentration of NO_X that affect sensitive plants over 0.5 to 8.0 hours of contact can be extrapolated to longer exposure periods to provide a framework for evaluating the importance of the project air pollutant concentrations. As noted by Heck and Brandt, to rely on this extrapolation for periods greater than 24 hours would be of questionable value.

Based on the modeling conducted the annual NO_2 ground level concentration is 93.49 $\mu g/m^3$. Converting this value to ppm yields a maximum annual impact of 0.05 ppm. This concentration is much smaller than the lowest concentration in the table above which has been determined to potentially lead to injury of sensitive vegetation. Modeling conducted over 1 and 8 hour averaging periods for a single year (1991) indicates maximum NO_2 concentrations of 4.36 ppm for a 1-hour average and 2.10 ppm for an 8-hour average. These maximum concentrations were modeled to occur on the fence line and immediately decrease well below impacts potentially harmful to the most sensitive vegetation. NO_2 emissions from the Wetumka Gas Plant are therefore not anticipated to lead to injury of vegetation.

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. As previously demonstrated, the maximum predicted NO_2 pollutant concentration from the gas plant is well below the secondary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated due to the existing facility.

4. Visibility Impairment

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.

5. 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 220 km east-northeast of the Wichita Mountain Wildlife Class I area and approximately 200 km north west of the Caney Creek Class I area.

Under guidance from the Land Manager representative for the Wichita Mountain Wildlife Class I area an evaluation was not necessary due to distance, emissions and status as a historical PSD action.

SECTION VIII. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application are duplicated below. Records are available to confirm the insignificance of the activities. Appropriate recordkeeping of activities indicated below with “*” is specified in the Specific Conditions.

1. *Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for peaking power service not exceeding 500 hours/year. Not currently on-site, chosen for future use.
2. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTUH heat input (commercial natural gas). There are two process heaters, two dehy. reboilers, and one glycol reclaimer rated below 5 MMBTUH.
3. Emission from stationary internal combustion engines rated less than 50-hp output. None on-site, chosen for future use.
4. *Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature. There are 14 tanks on-site in this category.
5. Gasoline and aircraft fuel handling facilities, equipment, and storage tanks except those subject to New Source Performance Standards and standards in 252:100-37-15, 252:100-39-30, 252:100-39-41, and 252:100-39-48. None on-site, chosen for future use.
6. Emissions from condensate tanks with a design capacity of 400 gallons or less in ozone attainment areas. None on site, chosen for future use.
7. Emissions from crude oil and condensate marine and truck loading equipment operations at crude oil and natural gas production sites where the loading rate does not exceed 10,000 gallons per day averaged over a 30-day period. None on-site, chosen for future use.

8. *Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. There are 14 tanks on-site in this category.
9. Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in 252:100-8-3(e)(1).
10. Cold degreasing operations utilizing solvents that are denser than air.
11. *Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes wood chipping operations not associated with the primary process operation. None on-site, chosen for future use.
12. Site restoration and/or bioremediation activities of <5 years expected duration.
13. Hydrocarbon contaminated soil aeration pads utilized for soils excavated at the facility only.
14. *Surface costing operations which do not exceed a combined total usage of more than 60 gallons/month of coatings, thinners, and clean-up solvents at any one emissionsunit. None on-site, chosen for future use.
15. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.
16. Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas.
17. *Activities having the potential to emit no more than 5 TPY (actual) of any criteria pollutant. Potential to emit of VOCs from the two methanol storage tanks is negligible. Continuous flare emissions and emissions of VOC from truck loading of condensate are in this category.

SECTION IX. 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.
Modeling results showed that maximum NO_2 concentration is 99 $\mu g/m^3$ and maximum CO concentration is 9.924 $\mu g/m^3$, compared to 100 $\mu g/m^3$ and 40,000 $\mu g/m^3$ of NAAQS, respectively.

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, 2002, 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 requirements are addressed in the “Federal Regulations” section.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for the past years.

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

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

Emission limitations for all the sources are taken from the construction permit application and the Title V 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. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. 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]
This subchapter specifies a particulate matter (PM) emissions limitation of 0.6 lb/MMBTU from fuel-burning equipment with a rated heat input of 10 MMBTUH or less, and 0.57, 0.56, and 0.51 lb/MMBTU for equipment with a rated heat input of 12.89, 14.3, and 21.48 MMBTUH, respectively. For 2-cycle lean-burn engines, 4-cycle lean-burn engines, and 4-cycle rich burn engines burning natural gas, AP-42 (7/00), Section 3.2 lists the total PM emissions as approximately 0.01 lbs/MMBTU. AP-42 (7/98), Section 1.4 lists natural gas TPM emissions to be 7.6 lbs/million SCF or about 0.0076 lbs/MMBTU which is in compliance with this subchapter. The permit requires the use of natural gas for all fuel-burning equipment to ensure compliance with Subchapter 19.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. When burning natural gas there is very little possibility of exceeding these standards.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions 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. Under normal operating conditions, this facility has negligible potential to violate this requirement; therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of hydrogen sulfide (H_2S) emissions from any existing source or new source to 0.2 ppm for a 24-hour average (equivalent to 280 $\mu g/m^3$). An analysis of inlet gas to this facility showed no hydrogen sulfide content.
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/million BTU heat input. This is equivalent to approximately 0.2 weight percent sulfur in the fuel gas which is equivalent to 2,000 ppmw sulfur. Thus, a limitation of 343 ppmv sulfur in a field gas supply will be in compliance. The permit requires the use of pipeline-grade natural gas or field gas with a maximum sulfur content of 343 ppmv for all fuel-burning equipment to ensure compliance with subchapter 31. Initial compliance testing of the fuel sulfur content and further testing whenever the gas supplier or gas field is changed will be used to ensure compliance with this limitation.
Part 5 also limits hydrogen sulfide emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). Removal of hydrogen sulfide in the exhaust stream, or oxidation to sulfur dioxide, is required unless hydrogen sulfide emissions would be less than 0.3 lb/hr for a two-hour average. An analysis of inlet gas to this facility showed no hydrogen sulfide content.

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.2 lb of NOx per MMBTU. There are no equipment items that exceed the 50 MMBTUH threshold.

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. This applies to the three 400-bbl condensate tanks and the two (one 8,400-gallon and one 1,000-gallon) methanol tanks.
Part 3 requires loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. This facility does not have the physical equipment (loading arm and pump) to conduct this type of loading. Therefore, this requirement is not applicable.
Part 5 limits the VOC content of coatings used in coating lines and operations of parts and products. This facility does not normally conduct coating or painting operations except for

routine maintenance of the facility and equipment which is exempt and considered a Trivial Activity.
Part 7 requires all effluent water separator openings which receive water containing more than 200 gallons per day of any VOC to be sealed or the separator to be equipped with an external floating roof or a fixed roof with an internal floating roof or a vapor recovery system. No effluent water separators are located at this facility.
Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. All of the pumps and compressors at this facility are subject to these requirements.
Part 7 also requires fuel-burning equipment to be operated and maintained so as to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion.

OAC 252:100-41 (Hazardous Air Pollutants 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 September 1, 2004, 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, J, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, YYYY, ZZZZ, AAAAA, BBBBB, CCCCC, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS and TTTTT are hereby adopted by reference as they exist on September 1, 2004. 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. Part 5 regulates sources of toxic air contaminants that have emissions exceeding a *de minimis* level. However, Part 5 of Subchapter 41 has been superseded by OAC 252:100-42. The Air Quality Council approved Subchapter 42 for permanent rulemaking on April 20, 2005. The Environmental Quality Board approved Subchapter 42 as both a permanent and emergency rule on June 21, 2005. The emergency Subchapter 42 was sent for Gubernatorial signature on June 30, 2005, and became effective by emergency August 11, 2005. Subchapter 42 is expected to become permanently effective on June 15, 2006. Because Subchapter 41, Part 5 has been superseded, the requirements of Part 5 will not be reviewed in this memorandum. Should Subchapter 42 fail to take effect, this permit will be reopened to address the requirements of Subchapter 41, Part 5.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Not Applicable]
All parts of OAC 252:100-41, with the exception of Part 3, shall be superseded by this subchapter. Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

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

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

SECTION X. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
PSD review has been addressed in previous sections.

NSPS, 40 CFR Part 60 [KKK Applicable]
Subpart Kb, VOL Storage Vessels. This subpart regulates hydrocarbon storage tanks larger than 19,812-gal capacity and built after July 23, 1984. All tanks on-site are below this threshold, thus they are exempt.
Subpart GG affects all stationary gas turbines which commenced construction, reconstruction, or modification after October 3, 1977, with heat input at peak load of greater than or equal to 10 MMBTUH based on the lower heating value of the fuel. There are no turbines on-site.
Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry. The equipment is not in a SOCMI plant.
Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This subpart applies to affected facilities that commence construction, reconstruction, or modification after January 20, 1984. Affected facilities include a compressor in VOC service or in wet gas service and the group of all equipment except compressors within a process unit. A compressor

station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system or liquefied natural gas unit is covered by this subpart if it is located at an onshore natural gas processing plant. Compressors E-508 and E-509 are not in VOC service. Inlet compression is provided by units 149, 144, 128, 127, and 126. Also because of operational flexibility, units 512, 511, 510, 602, 601, 603, 604, and 605 can also be utilized as inlet gas compression even though their primary purpose is for compression of non-VOC gas (either plant recompressor or injection/withdrawal within the storage field). Most of the above listed compressors were constructed prior to January 20, 1984 and are not subject to the NSPS subpart KKK regulation. However, the following compressors have commenced construction, reconstruction or modification after January 20, 1984 and are subject to NSPS subpart KKK regulation: Units 149, 510, 603, 604, and 605 (Units 604 and 605 are electric-driven compressors). The glycol dehydration units at the facility are not in wet gas service. The glycol dehydration units are used to reduce the water content to <7 lbs/mcf from the natural gas withdrawn from the storage field before being transported through transmission pipelines. The gas injected into the storage field is previously processed natural gas and/or gas that is non-processable (VOC content well below 10%). However, due to the recirculation of glycol, these dehydration units are considered in heavy liquid service, and shall comply with 60.482-8. Any applicable components added at the Facility as a result of the piping modifications will be added to the LDAR program.
Subpart LLL sets standards for natural gas sweetening units. There is no natural gas sweetening operation at this site.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, beryllium, benzene, 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 [Applicable]
Subpart HH, Oil and Natural Gas Production Facilities. This subpart applies to affected emission points that are located at facilities which are major sources of HAPs and either process, upgrade, or store hydrocarbons prior to the point of custody transfer or prior to which the natural gas enters the natural gas transmission and storage source category. For purposes of this subpart natural gas enters the natural gas transmission and storage source category after the natural gas processing plant. If no natural gas plant is present, natural gas enters the natural gas transmission and storage source category after the point of custody transfer. For gas processing, all HAP emission points at the site (e.g., amine treater vents, sulfur recovery plant emissions, or compressor engines, as well as dehydrators and tanks) must be considered. Based on formaldehyde emission factors obtained from AP-42 (7/00), Chapter 3.2, total formaldehyde emissions from engines on-site are estimated to be 18.84 TPY. Facility-wide HAP emissions including the two dehydrators prior to control are estimated to be 26.41 TPY. Therefore, this facility is a major source for HAPs and is subject to applicable requirements of this subpart. The applicant installed a condenser for the two dehydration units to reduce benzene emissions below 1.0 TPY. The condenser was installed on June 10, 2002, prior to the compliance date of June 17, 2002. Therefore, these two dehydrators are only subject to recordkeeping requirements for annual benzene emissions calculations.

Subpart EEEE, Organic Liquids Distribution (Non-Gasoline). This subpart was promulgated on February 3, 2004, and affects activities and equipment used to distribute organic liquids into, out of, or within a major source plant site. Four types of emission sources are included in the affected source: storage tanks storing organic liquids; transfer racks at which organic liquids are loaded into or unloaded out of transport vehicles and/or containers; the transport vehicles themselves while they are loading or unloading organic liquids at transfer racks; and equipment leak components in organic liquids service that are associated with pipelines and with storage tanks and transfer racks storing, loading, or unloading organic liquids. However, 63.2334(c) stated that organic liquid distribution operations do not include the activities and equipment, including product loading racks, used to process, store, or transfer organic liquids at oil and natural gas production field facilities, as the term "facility" is defined in Sec. 63.761 of Subpart HH. Therefore, this facility is not subject to this subpart.
Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart was promulgated on June 15, 2004, and affects the following RICE with a site rating greater than 500 brake horsepower and which are located at a major source of HAP emissions: existing, new, and reconstructed spark ignition 4 stroke rich burn (4SRB) RICE, any new or reconstructed spark ignition 2 stroke lean burn (2SLB) or 4 stroke lean burn (4SLB) RICE, or any new or reconstructed compression ignition (CI) RICE. Engines 601, 602, 126, 127, 128, 511, and 512 are subject to this subpart and must comply with the applicable emission limitations and operating limitations no later than June 15, 2007.

CAM, 40 CFR Part 64 [Not Applicable At This Time]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant.
- It uses a control device to achieve compliance with the applicable emission limit or standard.
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant in excess of major source levels.

Engines 601, 602, 126, 127, 512, and 511 have emission limits and control devices, however, each of these engines has potential emissions less than 100 TPY (Manufacturer' data is 10.0 gm/hp-hr and applicant uses 12 gram/hp-hr) after air-to-fuel controller but prior to catalytic converter. AQD's CAM guidance stated that for compressor engines required by a permit to be equipped with air-to-fuel ratio (AFR) controllers, the agency accepts emissions after the controller as pre-control emissions for CAM applicability purposes. The renewal of this permit will address whether the agency will accept Manufacturer's data for after AFR emission or testing will be required. The other engines are lean burn engines with no add on controls.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
The definition of a stationary source does not apply to transportation, including storage incident to transportation, of any regulated substance or any other extremely hazardous substance under the provisions of this part. The definition of a stationary source also does not include naturally occurring hydrocarbon reservoirs. Naturally occurring hydrocarbon mixtures, prior to entry into a natural gas processing plant or a petroleum refining process unit, including: condensate, crude oil,

field gas, and produced water, are exempt for the purpose of determining whether more than a threshold quantity of a regulated substance is present at the stationary source.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and F Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

This facility does not utilize any Class I & II substances.

SECTION XI. COMPLIANCE

Tier Classification & Public Review

This application has been determined to be a Tier II per OAC 252:4-7-32 based on the request for a PSD construction permit for a significant modification at an existing major facility.

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 possesses a current lease or easement given by the landowner for the purpose or purposes stated in the application.

The applicant published the “Notice of Filing a Tier II Application” in *The Hughes County TIMES*, a weekly newspaper in Wetumka, Hughes County, on August 16, 2001 for the permit application to address historic issues. The notice stated that the application was available for public review at the Wetumka Public Library, 202 North Main, Wetumka, OK 74883. The applicant published another “Notice of Filing a Tier II Application” in the same newspaper on December 9, 2005 for the new piping project. The applicant also published a “Notice of Draft Tier II Permit” in *The Hughes County TIMES* on January 26, 2006 to start public review for a period of 30 days. The notice stated that the application was available for public review at the Wetumka Public Library, 202 North Main, Wetumka, OK 74883. In addition, a copy of the draft permit was available at the AQD office in Oklahoma City, and on the Air Quality section of the DEQ web page at *www.deq.state.ok.us*. A concurrent EPA review started on January 23, 2006 and ended on March 9, 2006. No comments were received from the public or from the EPA. This site is not within 50 miles of another states border.

Testing

Engine testing results conducted on September 21, 2005, were provided which show compliance with the emission limits.

	Test Results		Emission Limits	
Source	**NOx lb/hr**	**CO lb/hr**	**NOx lb/hr**	**CO lb/hr**
E-601	0.02	0.44	4.23	4.23
E-602	0.2	0.14	4.23	4.23
E-126	1.25	0.22	4.23	4.23
E-127	0.3	0.44	4.23	4.23
E-128	8.89	9.45	35.27	28.15
E-511	0.03	0.33	4.23	4.23
E-512	0.1	0.19	4.23	4.23
E-144	2.15	2.23	15.76	3.15
E-508	13.05	2.37	15.76	3.15
E-509	9.16	2.65	15.76	3.15
E-510	8.25	5.02	9.09	18.19
E-603	11.70	11.80	24.25	21.22
E-149	2.28	5.49	8.82	13.23

Inspection

An initial Title V inspection was conducted on September 8, 2005 by Jian Yue of Air Quality. Mr. Lance Lodes of Enogex represented the facility during the visit. The facility was operating as described in the permit application and supplemental materials. Identification plates with the make, model, and serial number were attached to all engines.

Fees Paid

Construction permit fee of $2,000 and initial Title V operating permit fee of $2,000.

SECTION XII. SUMMARY

The facility is operated as described in the application. Ambient air quality standards are not threatened at this site. There is no active Air Quality compliance or enforcement issues concerning this facility other than Consent Order No. 01-160. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Enogex Products Corporation **Permit Number 97-118-C (PSD)**
Wetumka Gas Processing Plant

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on March 3, 1997 and August 20, 2001, with supplemental information submitted on November 30, 2001, October 21, 2002, October 15, 2003, August 15, 2005, and October 10, 2005. The Evaluation Memorandum, dated March 23, 2006, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction under this permit constitutes acceptance of, and consent to, the conditions contained herein.

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

EUG-1 Rich Burn Engines (Except for E-149)

EU	NOx		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
E-601	4.23	18.53	4.23	18.53	0.23	1.00
E-602	4.23	18.53	4.23	18.53	0.23	1.00
E-126	4.23	18.53	4.23	18.53	0.23	1.00
E-127	4.23	18.53	4.23	18.53	0.23	1.00
E-128	31.75	139.07	28.15	123.29	0.62	2.70
E-511	4.23	18.53	4.23	18.53	0.23	1.00
E-512	4.23	18.53	4.23	18.53	0.23	1.00
E-149	8.82	38.62	13.23	57.94	2.65	11.59

EUG-2 Engines Installed in 1984

EU	NOx		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
E-144	15.76	69.04	3.15	13.81	2.43	10.62
E-508	15.76	69.04	3.15	13.81	2.43	10.62
E-509	15.76	69.04	3.15	13.81	2.43	10.62

EUG-3 Engine Installed in 1985

EU	NOx		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
E-510	9.09	39.83	18.19	79.66	3.64	15.93

EUG-4 Engine Installed in 1985

EU	NOx		CO		VOC	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
E-603	24.25	106.22	21.22	92.94	6.06	26.55

EUG-5 Glycol Dehydrators

EU	VOC	
	lb/hr	TPY
DEHY2 (Still Vent)		
DEHY3 (Still Vent)	5.44	23.83

EUG-6

Emissions from the heaters and plant flare pilot are based on existing equipment and are considered insignificant activities with no specific emission limitations.

EU	Point	Description	Size MMBTUH
E-FLARE	P-FLARE	Emergency Flare	-
E-HTR1	P-HTR1	Process Heater	3.1
E-HTR2	P-HTR2	Process Heater	3.1
E-HTR3	P-HTR3	Dehy2 Reboiler	2.0
E-HTR4	P-HTR4	Dehy3 Reboiler	2.0
E-HTR5	P-HTR5	Glycol Reclaimer	0.4

EUG-7 Condensate Tanks VOC Emissions

EU	Annual Throughput (gal/yr)	VOC* (TPY)
E-TANK1		
E-TANK2	700,000	283.71
E-TANK3		

*Condensate tanks emissions estimates include working and breathing losses, and total flash emissions.

Condensate truck loading is considered an insignificant activity with no specific emission limitation.

EUG-8

Emissions from the following tanks are based on existing equipment and are considered insignificant activities with no specific emission limitations.

EU	Point	Description	Capacity (gallon)
E-TANK4	P-TANK4	Produced Water	8,400
E-TANK5	P-TANK5	Methanol	8,400
E-TANK6	P-TANK6	Used Oil	4,200
E-TANK7	P-TANK7	Engine Oil	1,000
E-TANK8	P-TANK8	Engine Oil	6,000
E-TANK9	P-TANK9	Engine Oil	1,000
E-TANK10	P-TANK10	Engine Oil	600
E-TANK11	P-TANK11	TEG	6,000
E-TANK12	P-TANK12	Coolant	2,000
E-TANK13	P-TANK13	Produced Water	4,200
E-TANK14	P-TANK14	Used TEG	4,800
E-TANK15	P-TANK15	Used TEG	420
E-TANK16	P-TANK16	Used TEG	420
E-TANK17	P-TANK17	Wash Soap	400
E-TANK18	P-TANK18	Oil/Coolant	205/46
E-TANK19	P-TANK19	Methanol	1,000

EUG-9 Fugitive Components

Total VOC emissions from fugitive equipment components subject to NSPS KKK are limited as follows:

EU	Point	Component	Number*	VOC (TPY)
E-FUG	P-FUG	Valves	3,570	39.57
		Pump Seals	40	
		Flanges	6,300	
		Relief Valves	100	

* Estimate only, not a permit limit.

2. The fuel-burning equipment shall use pipeline-grade natural gas or field gas with a maximum sulfur content of 343 ppmv. [OAC 252:100-31]

3. The permittee shall be authorized to operate this facility continuously (24 hours per day, every day of the year). [OAC 252:100-8-6(a)]

4. Each engine at the facility shall have a permanent identification plate attached which shows the make, model number, and serial number. [OAC 252:100-45]

5. Engines 126, 127, 601, 602, 511, and 512 shall each be set to operate with exhaust gases passing through a functional air-to-fuel ratio controller and a catalytic converter. [OAC 252:100-8-6(a)]

6. At least once per calendar quarter, the permittee shall conduct tests of NO_X and CO emissions in the exhaust gases from each engine and each replacement engine when operating under representative conditions for that period. Testing is required for the engine if it runs for more than 220 hours during a calendar quarter. Engines shall be tested no sooner than 20 days after the last test. Testing shall be conducted using a portable analyzer in accordance with a protocol meeting the requirements of the latest "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality. When four consecutive quarterly tests show an engine/turbine to be in compliance with the emissions limitations shown in the permit, then the testing frequency may be reduced to semi-annual testing. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. Upon any showing of non-compliance with emissions limitations or testing that indicates that emissions are within 10% of the emission limitations, the testing frequency shall revert to quarterly. Any reduction in the testing frequency shall be noted in the next required compliance certification. Reduced engine testing does not apply to engines with catalytic converters. [OAC 252:100-8-6 (a)(3)(A)]

7. When periodic compliance testing of each engine and each replacement engine shows engine exhaust emissions in excess of the lb/hr limits in Specific Condition Number 1, the permittee 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 of OAC 252:100-9 include immediate notification and written notification of Air Quality and demonstrations that the excess emissions meet the criteria specified in OAC 252:100-9. [OAC 252:100-9]

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

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

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

c. Replacement equipment and emissions are limited to equipment and emissions which are not subject to NSPS, NESHAP, or PSD, except those engines/compressors that are subject to NSPS Subpart KKK can be replaced.

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

9. The permittee shall keep operation and maintenance (O&M) records for those engines and replacement engines/turbines which do not conduct quarterly testing. Such records shall at a minimum include the dates of operation, and maintenance, type of work performed, and the increase, if any, in emissions as a result. [OAC 252:100-8-6 (a)(3)(B)]

10. Dehydrator DEHY1 shall be shutdown permanently or removed from the site.

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

11. The glycol dehydration units shall be operated as follows:

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

a. Dehydrators DEHY2 and DEHY3 shall be operated with a condenser that has a control efficiency which results in total benzene emissions not exceeding 1.0 TPY.
b. The discharge temperature of the glycol dehydration unit's condenser shall not exceed 130 ^{o}F.
c. All emissions from the glycol dehydration unit's still vent shall be vented through the condenser.
d. The condenser shall be equipped with a properly functioning thermometer to measure the outlet temperature of the condenser.
e. The permittee shall record the outlet temperature of the condenser at least monthly during daylight hours.
f. Each glycol dehydration unit shall be equipped with a flash tank on the rich glycol stream.
g. The off-gases from the flash tanks shall be routed to the station's inlet or the reboiler fireboxes.
h. The lean glycol recirculation rate of each glycol dehydration unit shall not exceed 14 gallons per minute and shall be recorded at least once per month. The natural gas throughput of the two glycol dehydration units shall not exceed 500 MMSCFD (monthly average based on actual operation hours).

12. The permittee shall comply with applicable requirements of NESHAP Subpart HH, National Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, for affected facilities. [40CFR 63.760 – 63.775]

a. Applicability and designation of affected source. [40CFR 63.760]
b. Test methods, Compliance procedures, and compliance demonstrations.

[40CFR 63.772(b)(2)]

On an annual basis, the permittee shall determine the actual average benzene emissions (in terms of benzene emissions per year) using the model GRI-GLYCalc, Version 3.0 or higher, and the procedures presented in the associated GRI-GLYCalc Technical

Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1).

c. Recordkeeping requirements [40CFR 63.774(d)(1)]

13. Total condensate throughput shall not exceed 16,667 barrels per 12-month rolling period.

14. The permittee shall comply with the Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants NSPS Subpart KKK, for each of the affected facilities. [40 CFR 60.630 to 60.636]

a. The owner/operator shall comply with the requirements of § 60.482-1(a), (b), and (d), and §§ 60.482-2 through 60.482-10 except as provided in § 60.333 [§ 60.632(a)]

(1) The owner/operator shall demonstrate compliance with §§ 60.482-1 to 60.482-10 for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485 unless the equipment is in vacuum service and is identified as required by § 60.486(e)(5). [§ 60.482-1(a), (b), & (d)]

(2) The owner/operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of § 60.482-2(a), (b), and (c) except as provided in §§ 60.482-2(d), (e), (f), and 60.633(d).

(3) Information and data used to demonstrate that a reciprocating compressor is in wet gas service or is not in VOC service shall be recorded in a log that is kept in a readily accessible location. [§§ 60.633(f), 60.635(c), & 60.486(j)]

(4) The owner/operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of § 60.482-4(a) and (b) except as provided in §§ 60-482-4(c) and 60.633(b).

(5) Sampling and connection systems are exempt from the requirements of § 60.482-5. [§ 60.633(c)]

(6) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.632(c). The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6]

(7) The owner/operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of § 60.482-7(b) through (e), except as provided in §§ 60.633(d), 60.482-7(f), (g), and (h), 60.483-1, 60.483-2, and 60.482-1(c). [§ 60.482-7(a)]

(8) The owner/operator shall comply with the monitoring and repair requirements, for pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of § 60.482-8(a) through (d).

[§ 60.482-8]

(9) Delay of repair of equipment is allowed if it meets one of the requirements of § 60.482-9(a) through (e).

(10) The owner/operators using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of § 60.482-10(b) through (g). [§ 60.482-10(a)]

b. An owner/operator may elect to comply with the alternative requirements for valves of §§ 60.483-1 and 60.483-2. [§ 60.632(b) & § 60.482-1(b)]

c. An owner/operator may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in NSPS Subpart KKK. In doing so, the owner or operator shall comply with requirements of § 60.634. [§ 60.632(c)]

d. The owner/operator shall comply with the test method and procedures of § 60.485 except as provided in §§ 60.632(f) and 60.633(h). [§ 60.632(d)]

e. The owner/operator shall comply with the recordkeeping requirements of § 60.486 and the reporting requirements of § 60.487 except as provided in §§ 60.633, 60.635, and 60.636.

[§ 60.632(e)]

f. The owner/operator shall comply with the recordkeeping requirements of § 60.635(b) and (c) in addition to the requirements of § 60.486. [§ 60.635(a)]

g. The owner/operator shall comply with the reporting requirements of § 60.636(b) and (c) in addition to the requirements of § 60.487. [§ 60.636(a)]

15. The permittee shall maintain records of operations as listed below. These records shall be maintained on-site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-8-6 (a)(3)(B)]

a. O&M records for any engine and for any replacement engine/turbine not tested in each 6 month period.
b. Operating hours of each engine and each replacement engine if operated less than 220 hours per quarter and not tested.
c. Periodic emission testing for each engine/turbine and each replacement engine/turbine.
d. Analysis of current fuel gas sulfur content (updated whenever the supply changes).
e. Facility condensate throughput (monthly and rolling 12-month totals).
f. Natural gas throughput of the two glycol dehydration units as specified in Specific Condition 11(H).
g. Glycol recirculation rate as specified in Specific Condition 11(H).
h. Benzene emissions as specified in Specific Conditions 11(A) and 12.
i. Condenser outlet temperature as specified in Specific Conditions 11(B) and 11(E).

16. The permittee shall maintain, and update annually, an inventory record of fugitive emission sources at the facility that are subject to NSPS Subpart KKK. The record shall include the following: [OAC 252:100-8-6 (a)(3)]

a. Type of service (gas, heavy oil, light oil, and water/light oil),
b. Component type and count, and
c. VOC content of stream handled based on a representative inlet gas analysis.

17. No later than 30 days after each anniversary date of the issuance of this permit, the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit. The following specific information for the past year is required to be included: [OAC 252:100-8-6 (c)(5)(A), (C) & (D)]

a. Testing results (quarterly or other applicable period) for any engine subject to emission limitations.
b. Operating hours for engines which operated less than 220 hours per quarter and not tested.
c. Summary of O&M records for any engine not tested in each 6 month period.
d. Condensate throughput (monthly and 12-month rolling total).
e. Benzene emissions as specified in Specific Conditions 11(A) and 12.
f. Records required by NSPS Subpart KKK (copy of most recent Semi-Annual Report submitted to the Administrator).

18. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations that qualify as Trivial Activities.
[OAC 252:100-8-6 (a)(3)(B)]

a. For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: records of capacity of the tanks and contents.
b. For space heaters, boilers, and process heaters less than or equal to 5 MMBtu/hr heat input: rated heat input.
c. For activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: type of activity and the amount of emissions from that activity (cumulative annual).

19. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility. [OAC 252:100-8-6(d)(2)]

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

PART 70 PERMIT

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

Permit No. 97-118-C (PSD)

Enogex Products Corporation

having complied with the requirements of the law, is hereby granted permission to construct the projects addressed in the Memorandum at the Wetumka Gas Processing Plant at Wetumka, Hughes County, Oklahoma ,

subject to the following conditions attached:

[x] Standard Conditions dated July 1, 2005

[x] Specific Conditions

______________________________ ______________________________

Division Director, Air Quality Division **Date**

Mr. Stephen Henderson
Enogex Products Corporation
P.O. Box 24300, MC E656
Oklahoma City, OK 73124-0300

Subject: Construction Permit No. 97-118-C (PSD)
Enogex Products Corporation (Enogex)
Wetumka Gas Processing Plant
Wetumka, Hughes County

Dear Mr. Henderson:

Air Quality Division has completed the initial review of your permit application referenced above. This application has been determined to be a **Tier II**. In accordance with 27A O.S. § 2-14-301 & 302 and OAC 252:4-7-13(c) the application and enclosed draft permit are now ready for public review. The requirements for public review include the following steps which you must accomplish:

1. Publish at least one legal notice (one day) in at least one newspaper of general circulation within the county where the facility is located. (Instructions enclosed)
2. Provide for public review (for a period of 30 days following the date of the newspaper announcement) a copy of this draft permit and a copy of the application at a convenient location (preferably a public location) within the county of the facility.
3. Send to AQD a copy of the proof of publication notice from Item #1 above together with any additional comments or requested changes which you may have on the draft permit.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4100 or the permit writer, Jian Yue, at (405) 702-4205.

Sincerely,

Dawson Lasseter, P.E., Chief Engineer
AIR QUALITY DIVISION
Enclosures

Mr. Stephen Henderson
Enogex Products Corporation
P.O. Box 24300, MC E656
Oklahoma City, OK 73124-0300

Subject: Construction Permit No. 97-118-C (PSD)
Enogex Products Corporation (Enogex)
Wetumka Gas Processing Plant
Wetumka, Hughes County

Dear Ms. Henderson:

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

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

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact the permit writer at (405) 702-4100.

Sincerely,

Jian Yue, P.E.
Engineering Section
AIR QUALITY DIVISION

Enclosures

Cc: Hughes County DEQ Office