OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **September 6, 2012**

TO: Phillip Fielder, P.E., Permits and Engineering Group Manager

THROUGH: Kendal Stegmann, Senior Environmental Manager
Compliance and Enforcement

THROUGH: Phil Martin, P.E., Engineering Manager, Existing Source Permit Section

THROUGH: Peer Review

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Permit Application No. **2012-1026-C PSD**
Mid-America Midstream Gas Services, L.L.C.
Buffalo Creek Processing Plant (1321)
NE/4 of Section 3, T10N, R25W, Beckham County
Latitude: 35.374°N; Longitude: 99.826°W
Directions: from Junction of I-40 and SH 152 travel 14 miles northwest on Highway 152 and then 0.5 miles south on County Road N1770, the facility is located on west side of the road.

SECTION I. INTRODUCTION

Bluestem Gas Services, L.L.C. (BGS), subsidiary of Chesapeake Midstream Partners, L.P., operates the N.E. Mayfield (NEM) Gas Plant as authorized by Permit No. 2009-276-TVR2 which was issued on July 16, 2010. Another Chesapeake entity, Mid-America Midstream Gas Services, L.L.C. (MAMGS), a subsidiary of Chesapeake Energy, proposes to construct a new facility, the Buffalo Creek Processing Plant. Due to the proximity of the new location and the fact that both operating companies are Chesapeake entities, these facilities are considered a single facility. However, separate Part 70 permits will be issued to each of the facilities. For PSD and permitting the emissions from each facility will be considered for each of the facilities but the permits and memos will only address the applicability of rules and regulations for the facilities separately.

MAMGS proposes to construct a natural gas plant with ten natural gas-fired reciprocating internal combustion engines, two natural gas-fired turbines, a 230-MMSCFD amine unit with a 11.04 MMBTUH reboiler, an acid gas flare, eight condensate tanks, and six produced water tanks. Associated support operations include condensate truck loading, blowdowns and fugitive emissions.

SECTION II. FACILITY DESCRIPTION

Buffalo Creek Processing Plant (BCPP)

The natural gas inlet stream from surrounding area wells enters the facility through an inlet separator. Liquids from the inlet gas stream are first sent to the stabilizer unit, which is designed to process liquid hydrocarbons by removing water and separating the lighter hydrocarbons from the heavier hydrocarbons. Water is sent to the slop water system and hydrocarbon liquid is sent to a series of filters to remove impurities present in the stream. Liquid is sent to the stabilizer reboiler, which uses hot oil to partially vaporize the liquid. The hot stabilized condensate is separated out in the weir section of the reboiler, flows through the stabilizer product cooler, and is then sent to condensate product storage. Hydrocarbon vapors from the separator are sent to the stabilizer overhead compressor system.

The combined inlet gas and stabilizer overhead streams flow first to the amine unit for CO_2 removal. The amine solution chemically reacts by absorbing CO_2 from the gas. Treated gas from the scrubber is sent to the dehydration unit. The liquid from the scrubber is sent to the amine regeneration unit. The rich amine at the bottom of the amine contactor enters the amine regeneration unit as it flashes across the level control valve to low pressure. The flashed liquids flow to the amine flash where the hydrocarbon vapors are released under pressure control to the flare. CO_2 rich water vapors from the overhead of the amine still are condensed in the amine still reflux condenser. The resulting water CO_2 stream flows to the amine still reflux accumulator where CO_2 gases are vented under pressure control to the flare.

After exiting the amine unit, the combined inlet gas and stabilizer overhead streams flow to the molecular sieve dehydration unit for water removal. Water vapor is absorbed and retained within the molecular sieve during the dehydration cycle. Regeneration of the molecular sieve is accomplished using a residue gas stream at a pressure equal to the inlet gas. The molecular sieve must be heated with regeneration gas for a period of 3.5 hours to ensure complete regeneration of the absorption catalyst.

After dehydration, the inlet gas will be processed in a cryogenic liquid recovery unit. The proposed cryogenic unit is designed to recover ethane contained in the feed gas while operating in the ethane recovery mode and propane contained in the feed gas while operating in the propane recovery mode. Cooled gas goes to the residue gas compressors where the pressure is further increased to meet the required pipeline delivery specifications. The cryogenic unit has been designed to switch from NGL recovery to ethane rejection mode. Due to the richness of the gas, a mechanical refrigeration system is provided to supplement the cooling of the feed gas. The refrigeration system is a closed loop system with two rotary screw refrigeration compressors driven by electric motors. Propane is utilized as the refrigerant.

SECTION III. EQUIPMENT

Buffalo Creek Processing Plant (BCPP)

BCPP-EUG A. Reciprocating Internal Combustion Engines

EU	Point	Make/Model	hp	Serial #	Mfg. Date
C-1	C-1	Caterpillar G3608LE W/OC	2,370	BEN00541	1/09
C-2	C-2	Caterpillar G3608LE W/OC	2,370	BEN00549	2/09
C-3	C-3	Caterpillar G3608LE W/OC	2,370	BEN00554	3/09
C-4	C-4	Caterpillar G3608LE W/OC	2,370	BEN00559	3/09
C-5	C-5	Caterpillar G3606LE W/OC	1,775	TBD	TBD
C-6	C-6	Caterpillar G3606LE W/OC	1,775	TBD	TBD
C-7	C-7	Caterpillar G3606LE W/OC	1,775	TBD	TBD
C-8	C-8	Caterpillar G3606LE W/OC	1,775	TBD	TBD
C-9	C-9	Caterpillar G3606LE W/OC	1,775	TBD	TBD
C-10	C-10	Caterpillar G3606LE W/OC	1,775	TBD	TBD

W/OC - with oxidation catalyst; TBD - To be determined.

BCPP-EUG B. Combustion Turbines

EU	Point	Make/Model	hp	Serial #	Mfg. Date
T-1	T-1	Solar Taurus 70-10802S	10,179	TBD	TBD
T-2	T-2	Solar Taurus 70-10802S	10,179	TBD	TBD

TBD - To be determined.

BCPP-EUG C. Gas-Fired Heater

EU	Point	Description	MMBTUH	Const. Date
H-1	H-1	Regeneration Heater	11.04	TBD

TBD - To be determined.

BCPP-EUG D. Amine Unit

EU	Point	Name	Throughput	Const. Date
AMINE-1	AMINE-1	Amine Unit	230 MMSCFD	TBD

TBD - To be determined.

BCPP-EUG E. Flares

EU	Point	Emission Unit	Const. Date
FLARE-1	FLARE-1	Acid Gas Flare	TBD
FLARE-2	FLARE-2	Main Plant Flare	TBD

TBD - To be determined.

BCPP-EUG F. Condensate Tanks

EU	Point	Contents	Barrels	Gallons	Const. Date
TK-1	TK-1	Condensate	400	16,800	TBD
TK-2	TK-2	Condensate	400	16,800	TBD
TK-3	TK-3	Condensate	400	16,800	TBD
TK-4	TK-4	Condensate	400	16,800	TBD
TK-5	TK-5	Condensate	400	16,800	TBD
TK-6	TK-6	Condensate	400	16,800	TBD
TK-8	TK-8	Condensate	400	16,800	TBD

TBD - To be determined.

BCPP-EUG G. Produced Water Tanks

EU	Point	Contents	Barrels	Gallons	Const. Date
PW-1	PW-1	Produced Water	200	8,400	TBD
PW-2	PW-2	Produced Water	200	8,400	TBD
PW-3	PW-3	Produced Water	200	8,400	TBD
PW-4	PW-4	Produced Water	200	8,400	TBD
PW-5	PW-5	Produced Water	200	8,400	TBD
PW-6	PW-6	Produced Water	200	8,400	TBD

TBD - To be determined.

BCPP-EUG H. Truck Loading

EU	Point	Name	Throughput	Const. Date
L-1	L-1	Condensate Truck Loading	1,460 MBPY	TBD

TBD - To be determined.

BCPP-EUG I. Fugitives

EU	Point	Number Items	Type of Equipment
FUG	FUG	762	Valves
		2,661	Flanges
		13	Open-ended Lines
		5	Pump Seals
		39	Other

BCPP-EUG J. Blowdowns

EU	Point	Name	Throughput	Const. Date
BD	BD	Blowdowns	1.44 MMSCFY	TBD

TBD - To be determined.

Engine Parameters

Source (make/model)	Height (feet)	Diameter (inches)	Flow (ACFM)	Temp. (˚F)	Fuel[1] (SCFH)
Caterpillar G3608LE W/OC	28	22	16,123	858	17,882
Caterpillar G3606LE W/OC	28	20	12,132	847	13,431
Solar Taurus 70-10802S[2]	40	66	112,854	897	79,020

[1] - based on a fuel heat content of 1,000 BTU/SCF (HHV); W/OC - with oxidation catalyst.

[2] - based on maximum fuel consumption @ 0 ˚F.

SECTION IV. PSD REVIEW

Total potential emissions of SO_2 from the NEM Gas Plant are greater than the major source threshold of 250 TPY. Any increase of emissions must be evaluated for PSD if they exceed a significance level (100 TPY CO, 40 TPY NO_X, 40 TPY SO_2, 40 TPY VOC, 15 TPY PM_{10}, 10 TPY H_2S).

A. Project Emission Increases

A project is a major modification if it causes a significant emissions increase and a significant net emission increase. A significant emissions increase of a regulated NSR pollutant will occur if the sum of emissions increases for each EU equals or exceeds the amount that is significant for that pollutant. Since this facility is wholly separate from the existing facility, there will be no associated emission increases from the existing emission units and all of the affected emission units are considered new emission units. For each EU, the emission increases are based on the difference between the “potential emissions” (PTE) and the “baseline actual emissions” (BAE). New emissions units must use their PTE and BAE are equal to zero. Fugitive emissions are excluded because the plant is not subject to a New Source Performance Standard (NSPS) promulgated prior to August 7, 1980, and the facility is not one of the 26 listed source categories.

Potential to Emit/Project Emission Increases

	NO_X	CO	VOC	SO_2	$PM_{10}/PM_{2.5}$	CO_{2e}
Point	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
C-1	11.44	12.59	5.03	0.05	0.78	9,164
C-2	11.44	12.59	5.03	0.05	0.78	9,164
C-3	11.44	12.59	5.03	0.05	0.78	9,164
C-4	11.44	12.59	5.03	0.05	0.78	9,164
C-5	8.57	9.43	3.77	0.03	0.59	6,883
C-6	8.57	9.43	3.77	0.03	0.59	6,883
C-7	8.57	9.43	3.77	0.03	0.59	6,883
C-8	8.57	9.43	3.77	0.03	0.59	6,883
C-9	8.57	9.43	3.77	0.03	0.59	6,883
C-10	8.57	9.43	3.77	0.03	0.59	6,883
T-1	20.77	21.11	12.11	0.23	2.54	44,949
T-2	20.77	21.11	12.11	0.23	2.54	44,949
H-1	2.18	3.43	0.26	0.03	0.36	5,658
FLARE-1	3.06	16.65	2.46	26.57	0.34	23,071
FLARE-2	0.35	1.80	3.55	0.01	0.04	576
PW1-6	---	---	2.96	---	---	229
L-1	---	---	49.08	---	---	176
FUG	---	---	7.06	---	---	517
BD	---	---	6.27	---	---	528
Totals	**144.31**	**171.04**	**138.60**	**27.45**	**12.48**	**198,607**
SER	**40**	**100**	**40**	**40**	**15/10**	**75,000**
>SER	**YES**	**YES**	**YES**	**NO**	**NO/YES**	**YES**

Since the project results in a significant emission increase for NO_X, CO, O_3 (for VOC and NO_X), $PM_{2.5}$ (for direct $PM_{2.5}$ and NO_X), and CO_{2e}, this project is subject to PSD and requires the facility to apply BACT to each emission unit at which a net increase in the pollutant would occur, to conduct a facility air quality impact analysis for each regulated pollutant that exceeds the significant emission increase, and monitoring, if applicable. There are currently no applicable modeling or monitoring requirements for CO_{2e}.

B. BACT

BACT shall apply to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. The following EU are subject to the BACT requirements:

Point	Emission Unit	NO_X TPY	CO TPY	VOC TPY	$PM_{2.5}$ TPY	CO_{2e} MTPY
C-1	2,370-hp Caterpillar G3608LE	11.44	12.59	5.03	0.78	9,164
C-2	2,370-hp Caterpillar G3608LE	11.44	12.59	5.03	0.78	9,164
C-3	2,370-hp Caterpillar G3608LE	11.44	12.59	5.03	0.78	9,164
C-4	2,370-hp Caterpillar G3608LE	11.44	12.59	5.03	0.78	9,164
C-5	1,775-hp Caterpillar G3608LE	8.57	9.43	3.77	0.59	6,883
C-6	1,775-hp Caterpillar G3608LE	8.57	9.43	3.77	0.59	6,883
C-7	1,775-hp Caterpillar G3608LE	8.57	9.43	3.77	0.59	6,883
C-8	1,775-hp Caterpillar G3608LE	8.57	9.43	3.77	0.59	6,883
C-9	1,775-hp Caterpillar G3608LE	8.57	9.43	3.77	0.59	6,883
C-10	1,775-hp Caterpillar G3608LE	8.57	9.43	3.77	0.59	6,883
T-1	10,179-hp Solar Taurus 70-10802S	19.49	19.75	11.30	2.39	42,355
T-2	10,179-hp Solar Taurus 70-10802S	19.49	19.75	11.30	2.39	42,355
H-1	11.04 MMBTUH Regen. Heater	2.18	3.43	0.26	0.36	5,658
FLARE1	Acid Gas Flare	3.06	16.65	2.46	0.34	23,071
FLARE	Main Plant Flare	0.35	1.80	3.55	0.04	576
PW-1-6	Produced Water Storage Vessels	---	---	2.96	---	229
L-1	Condensate Truck Loading	---	---	49.08	---	176
BD	Blowdowns	---	---	6.27	---	528

Startup, shutdown, and maintenance (SSM) activities for the engines and turbines are included in this review. Based on operational parameters no SSM BACT was needed for any of the affected emission units.

1. Top Down Process

BACT results in a specific emission limitation based on the maximum degree of reduction for each pollutant and emission unit, on a case-by-case basis, taking into account technical feasibility, energy, environmental, and economic impacts. The case-by-case BACT determination results from an analysis referred to as a "top down" analysis.

The "top down" analysis required for BACT involves the identification of all applicable control technologies in order of effectiveness. The review is then conducted beginning with the "top", or most effective emission control and/or reduction technology to determine if the technology is technologically, environmentally, and economically feasible. If the analysis reveals that a technology is not feasible based on any of these criteria, the next most effective control technology is then evaluated in the same manner. This is continued until the control technology under consideration cannot be eliminated based on technological feasibility, environmental impacts, or economics. This control technology is then proposed as BACT.

The top down BACT approach must not only look at the most stringent emission limits previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc. These technologies and emission limits are generally identified through a review of the EPA RACT/BACT/LAER Clearinghouse (RBLC). If the proposed BACT is equivalent to the most stringent emission limit (top), no further analysis is necessary. However, if the most stringent emission limit is not selected, additional analyses are required. Any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic" impacts, as described previously.

The determination of what constitutes BACT is left to the ODEQ, and allows that agency to consider the weight or emphasis to be placed on the energy, environmental, and economic impacts of control. This allows the state agency to consider, on a case-by-case basis, the size of the facility, the increment of air quality which will be absorbed by any particular major-emitting facility, anticipated and desired economic growth for the area, and other concerns that may impact the agency's decision-making process. In no event can the application of BACT be less stringent than any applicable NSPS or NESHAP standard. BACT should be established as a numerical emission limit or standard in the permit.

The five basic steps involved in the "top down" BACT analysis are listed below:

Step 1. Identify Available Control Technologies
Step 2. Eliminate Technically Infeasible Options
Step 3. Rank Remaining Control Technologies by Control Effectiveness
Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic Impacts
Step 5. Select BACT and Document the Selection as BACT

If due to technological or economic limitations to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

2. Green House Gases (GHG)

For the purpose of the BACT analysis, GHG is assumed to be composed primarily of CO_2, with much smaller quantities of CH_4 and N_2O. Under EPA's new guidelines for GHG BACT, the typical top-down analysis approach is to be followed. Since CO_2 is not typically feasible to control, the available control options focus on potential improved process efficiency, leading to improved fuel efficiency, rather than end-of-stack types of control systems.

One end-of-stack control option to be considered is geologic sequestration of GHG. However, sequestration is not yet commercially available and appropriate geologic formations have not been proven for long-term underground storage in the vicinity of the facility. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and require further study. Therefore, geologic sequestration is not considered to be a technically feasible control option at this time and is therefore eliminated from further consideration in this analysis. In addition, since sequestration is not yet commercially available, it is not possible to accurately estimate control costs. Use of alternative fuels, or fuel switching, is a control option that would typically be considered in the top-down CO_{2e} BACT analysis. Combustion of natural gas produces less GHG emissions per unit of energy than other fossil fuels. For CO_{2e}, the resulting BACT for all proposed equipment other than the RICE and turbines is efficiency and good work practices.

3. <u>Engines</u>

The facility is proposing to install ten natural gas fired spark ignition (SI) reciprocating internal combustion engines (RICE) at the Buffalo Creek Processing Plant. Four of the proposed RICE will be Caterpillar G3608LE compressor engines rated at 2,370-hp, and six of the proposed RICE will be Caterpillar G3606LE compressor engines rated at 1,775 hp. Both models are four-stroke lean-burn (4SLB). The BACT analysis for the engines is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The proposed engines will be subject to 40 CFR Part 60, NSPS, Subpart JJJJ and 40 CFR Part 63, NESHAP, Subpart ZZZZ. The standards for natural gas fired engines with a maximum horsepower rating greater than or equal to 500-hp which are manufactured after July 1, 2010, are 1.0 g/hp-hr NO_X, 2.0 g/hp-hr CO, and 0.7 g/hp-hr for VOC.

Step 1 - Identify Available Control Technologies

A review of previous BACT analyses was conducted to identify available control technologies for consideration. The search was conducted for 4SLB SI RICE ≥ 500-hp. The applicant queried the database for determinations between January 2005 and July 2010 for engines operating under the same SIC Code. AQD review included all SIC Codes for similar operations. According to RBLC, the proposed lean-burn engines have the lowest emissions of CO and VOC in comparison with other engines operating under the same SIC Code (1311 & 1321). The search results for CO and VOC are summarized below.

RBLC Search Results for CO

RBLC ID	SIC Code	Emission Rate (g/hp-hr)	RBLC ID	SIC Code	Emission Rate (g/hp-hr)
IA-0077	4922	0.2	WV-0020	4922	2.1
CO-0058	4922	0.2	IL-0083	4922	2.2
GA-0141	4922	0.2	WY-0066	1311	2.4
TX-0364	1321	1.2	TX-0408	2819	3.0
TX-0364	1321	1.2	LA-0141	1321	3.0
TX-0364	1321	2.0	TX-0364	1321	4.8
TX-0501	1321	2.0			

The proposed BACT emission limit for CO (0.55 g/hp-hr) is similar to the levels indicated and the control (oxidation catalyst) is equivalent to the types of controls installed on the engines listed. The three lowest emissions limits are based on installation of an oxidation catalyst and 93% control of CO emissions in accordance with 40 CFR Part 63, Subpart ZZZZ (MACT). However, the NO_X emission limits for these engines were permitted at a higher emission level (~1.0 g/hp-hr) resulting in reduced CO emissions. The engines proposed for installation at this facility are manufactured and set for the lowest possible NO_X setting (0.50 g/hp-hr) which increases the CO emissions. The proposed BACT is also due to the type of catalyst and the catalyst manufacturer's guarantee of 80% control efficiency. The catalyst is optimized for control of formaldehyde and VOC which results in a reduction in the control efficiency of CO.

RBLC Search Results for VOC

RBLC ID	SIC Code	Emission Rate (g/hp-hr)	RBLC ID	SIC Code	Emission Rate (g/hp-hr)
LA-0232	4922	0.2	IA-0077	4922	0.7
TX-0364	1321	0.3	WV-0020	4922	0.7
CO-0058	4922	0.3	WY-0066	1311	0.9
GA-0104	4922	0.3	TX-0364	1321	1.2
IL-0083	4922	0.4	TX-0408	2819	1.2
LA-0141	1321	0.5	TX-0501	1321	1.4
TX-0364	1321	0.6	TX-0364	1321	1.6

The proposed BACT emission limit for VOC (0.22 g/hp-hr) is equivalent to the listed levels and type of control (oxidation catalyst) so no further analysis was conducted since it is the most stringent control.

The proposed BACT for $PM_{2.5}$ is the burning of natural gas and good combustion with emissions based on AP-42 (8/2000), Section 3.2 for 4-cycle lean burn engines (0.01 lb/MMBTU). There were no BACT determinations for $PM_{2.5}$ on the RBLC. There were some BACT determinations for PM_{10} which are listed below. However, for each of the determinations no controls were proposed. Therefore, no further analysis was conducted.

RBLC Search Results for PM_{10}

RBLC ID	SIC Code	Emission Rate (lb/MMBTU)
IA-0077	4922	0.01
WV-0020	4922	0.04
TX-0364	1321	0.01
TX-0364	1321	0.03
TX-0364	1321	0.05
TX-0408	2819	0.02

Additional information on control technologies for lean-burn engines was found in the EPA Report, "Stationary Reciprocating Internal Combustion Engines, Updated Information on NO_X Emissions and Control Techniques, Revised Final Report" (2000). The NO_X control technologies identified for the engines are presented below.

Possible NO_X Control Technologies for Engines

Pollutant	Control Technology
NO_X	Selective Non-Catalytic Reduction (SNCR)
	Selective Catalytic Reduction (SCR)
	Lean-Burn Combustion (LBC)

Step 2 - Eliminate Technically Infeasible Options (NO_X)

Analysis of control technologies indicated that SNCR is not technically feasible for NO_X control. The use of SNCR requires injecting ammonia or urea into areas of the exhaust gas with temperatures in the range of approximately 1600 ºF to 2100 ºF to achieve proper NO_X reduction. If the exhaust gas is not at the correct operating temperature, SNCR requires additional fuel to heat the exhaust gas. In addition, SNCR can result in un-reacted ammonia or ammonia slip when temperatures are not in the optimum reaction range or when excess ammonia is injected into the exhaust gas. Typically, lower temperatures will cause an increase in the production of ammonia slip. The proposed engines for the facility will have exhaust gas temperatures of approximately 847 ºF to 870 ºF, depending on load capacity. This temperature range is well outside the optimum operating range for SNCR which would result in the production of ammonia slip and the inefficient reduction of NO_X emissions. This technology is not technically feasible for this engine; therefore, SNCR has been eliminated from BACT consideration and will not be discussed further.

Analysis of control technologies indicated that SCR is not technically feasible for NO_X control. Like the SNCR system, SCR requires injecting an ammonia or urea solution into the exhaust gas; however, SCR allows the reaction to occur at lower temperatures due to the introduction of a catalyst bed. The ammonia or urea injection system can again result in the production of un-reacted ammonia or ammonia slip. In order to ensure that correct amount of ammonia or urea is injected into the system, SCR typically includes monitoring systems upstream and/or downstream of the catalyst bed to function as a feedback system.

Many current systems utilize urea for the reagent as opposed to ammonia solutions. In urea systems, the first stage of the catalyst bed is the hydrolysis catalyst, which converts the urea to ammonia. The second stage of the catalyst allows ammonia and NO_X to react and forms nitrogen gas and water. As a secondary reaction, hydrocarbons react with oxygen to form water, carbon dioxide, and carbon monoxide. The third stage of the catalyst bed includes an oxidation catalyst where un-reacted ammonia oxidizes to form nitrogen gas and water.

While SCR is technically capable of controlling NO_X emissions from a natural gas-fired lean-burn SI engine, there are several operating limitations to the technology when utilized for engines in load-following applications. Potential limitations due to load-following include variations in NO_X emission rates, variations in exhaust gas flow and temperature, and thermal cycling (i.e., the rise and fall of gas temperature which can shorten the catalyst life). These issues can make it difficult to maintain a high level of control in SCR systems while also minimizing the production of ammonia slip. Ammonia slip production can also cause increased catalyst corrosion. Variable exhaust gas temperatures may cause un-reacted NO_X and ammonia to pass through the catalyst which can result in an inefficient reduction of NO_X emissions and the release of the un-reacted ammonia as emissions from the stack. This technology is not technically feasible for the engines at this facility due to the potential problems incurred when utilized in a load-following application.

A review of the RBLC database indicates that SCR technology has not been utilized as BACT for any natural gas-fired lean-burn SI engine during the last five years. Additionally, only seven natural gas-fired lean-burn SI engines have had SCR installed between 1991 and 2001, according to the EPA Report. The EPA Report also references one facility that utilized SCR for control of a lean-burn SI engine from 1984 to 1996. While the SCR system met or exceeded a NO_X control efficiency of 70%, the facility experienced difficulty in operation and maintenance of the system citing that it required work beyond that normally required for the particular engine. It should also be noted that the facility reported increased costs incurred due to the SCR system. Operating expenses included the continuous emissions monitoring system (CEMS), ammonia reagent, and catalyst replacement. The CEMS posed additional problems in that facility personnel were required to learn new analytical and instrumental skills. In addition, neighbors were opposed to the transport and storage of hazardous anhydrous ammonia at the facility. These collective issues led to the ultimate removal of this engine as well as a second identical engine at another facility.

The RBLC review and EPA report serve as further demonstration that SCR is not a feasible control technology for natural gas-fired lean-burn SI engines, especially when utilized in applications that result in variable load capacities and when located at unmanned facilities.

Lean-burn combustion technology utilizes several technologies to maximize the operation of the engine while also lowering NO_X emissions. One step in the lean-burn technology is adjusting the air to fuel ratio. Extra air dilutes the combustion gases from the stack which lowers the flame temperature at maximum compression and reduces thermal NO_X formation. To avoid de-rating the engine, a turbocharger is required to increase the combustion air to a constant fuel flow rate. To maintain the optimum air to fuel ratio, an automated air to fuel ratio controller is typically used on the engine.

Another step in lean-burn combustion is spark timing retard which is achieved by delaying the ignition spark until after the compression cycle is at maximum compression. Because the combustion chamber is not at its minimum, the peak flame temperature will be reduced, and will in turn reduce NO_X formation. An electronic ignition and injection control system is usually required for engines operated at variable load capacities.

Lastly, lean-burn combustion technology includes pre-combustion chamber (PCC) technology. The majority of the air/fuel mixture within the engine cylinders is too lean to be ignited by the spark plug. With PCC technology, a relatively small chamber in the cylinder is supplied with a rich air/fuel mixture which can be ignited by the spark plug. Ignition in this small chamber then ignites the lean air/fuel mixture in the rest of the cylinder, thus producing enhanced ignition and improved mixing.

A review of NO_X control technologies for large (>500 hp) natural gas-fired internal combustion engines on the RBLC demonstrates that a preferred method for natural gas-fired SI engines is the utilization of lean-burn combustion technology which is inherent to the design of the proposed engines and does not require any additional equipment or systems to achieve a reasonable level of NO_X emissions.

In contrast to SCR, lean-burn combustion technology is able to follow load swings without the increased potential of high NO_X emissions or ammonia slip production. Since it is incorporated into the engine by design, it does not pose as great of a risk of engine failure as SCR. Based on a review of the applicable technologies, the RBLC, and the EPA Report, lean-burn combustion technology appears to be the most preferred technically feasible method of NO_X emissions control for natural gas-fired SI engines.

Step 3 - Rank Control Technologies by Control Effectiveness (NO_X)
The next step is to rank control technologies not eliminated due to technical infeasibility in order of decreasing effectiveness. SCR has been eliminated due to technical infeasibility; however, it has been evaluated further to demonstrate the economic feasibility of the technology.

Ranking of Control Technologies by Effectiveness

Pollutant	Control Technology	Control Level
NO_X	Selective Catalytic Reduction (SCR)	0.05 g/hp-hr
	Ultra Lean-Burn Combustion (ULBC)	0.50 g/hp-hr
	Lean-Burn Combustion (LBC)	0.70 g/hp-hr

Step 4 - Evaluate Most Effective Controls Based on Impacts (NO_X)
Although SCR technology may be infeasible in practice, the highest NO_X reductions could theoretically be achieved using this technology. Therefore, the economic feasibility of this control option was evaluated. The result was that the reduction in NO_X emissions using SCR is not economically feasible based on overall cost estimates and incremental reduction of emissions from the proposed emission limit (0.5 g/hp-hr) as shown below.

The cost for the initial purchase and installation of the SCR and ammonia or urea reagent for the SCR is approximately \$231,223 for the Caterpillar G3608LE and \$194,081 for the Caterpillar G3606LE. This cost includes the purchase of an oxidation catalyst which must be installed after the SCR to control the production of ammonia slip. Ammonia or urea must be continually purchased for use in the injection system. The cost of urea is approximately \$35,000 per year depending on the current market price for urea at the time of purchase. The SCR catalyst and other process elements must be cleaned after 5 years of use. In addition, the oxidation catalyst requires additional maintenance and cleaning costs. A comparison table of the cost estimates for additional reductions from a SCR added to a ULBC engine and a ULBC are presented below.

SCR VS ULBC Cost Comparison for CAT G3608LE Engines

Factor	SCR	ULBC
Total Capital Investment	$231,223	$ 0
Total Direct Annual Cost	$62,342	$ 0
Total Indirect Annual Cost	$42,170	$ 0
Total Annualized Cost	$104,512	$ 0
Design Control Efficiency	90%	75%
Tons NO_X Removed per Year	10.3	34.33
Cost Effectiveness per Ton of NO_X Removed	$10,149	N/A

SCR VS ULBC Cost Comparison for CAT G3606LE Engines

Factor	SCR	ULBC
Total Capital Investment	$194,081	$ 0
Total Direct Annual Cost	$62,342	$ 0
Total Indirect Annual Cost	$35,396	$ 0
Total Annualized Cost	$97,738	$ 0
Design Control Efficiency	90%	75%
Tons NO_X Removed per Year	7.7	25.71
Cost Effectiveness per Ton of NO_X Removed	$12,672	N/A

Step 5 - Select BACT and Document the Selection as BACT (NO_X)

The additional cost of the SCR system is too high and is not warranted or justified for the engines at this facility based on the relatively low additional reduction in NO_X emissions. Due to the collective technical and economic infeasibility of SCR, the technology has been eliminated as BACT for the proposed engines at this facility. Natural gas-fired lean-burn SI engines without add-on controls for NO_X can meet or exceed a NO_X emission limit that is equivalent to the NSPS Subpart JJJJ requirements for SI ICE of 1.0. The lean-burn combustion technology is a low emission technology and is already integrated into the proposed engines as purchased. Thus, this technology does not result in any additional costs beyond the cost of the initial purchase and the normal operation and maintenance of the engine. Therefore, the proposed BACT is no add-on controls for the lean-burn engines with a manufacturer's emission guarantee for the proposed engine of 0.5 g/hp-hr.

Additional Review for Greenhouse Gases (CO_{2e})

Because geologic sequestration has been eliminated as a control option due to technical infeasibility, and because this engines already burn natural gas, the only remaining control option to consider is efficiency. Based on the mechanical drive portion of the engines, the efficiency of the engines is estimated at 37.4%. BACT for this unit is natural gas combustion and good design and combustion practices.

Summary of Proposed BACT for Engines

Pollutant	Control Technology	Proposed Emission Level
NO_X	Lean-Burn Combustion	0.50 g/hp-hr
CO	Oxidation Catalyst	0.55 g/hp-hr
VOC	Oxidation Catalyst	0.22 g/hp-hr
$PM_{2.5}$	Natural Gas Combustion	0.01 lb/MMBTU[1]
CO_{2e}	Efficient Design & Combustion	≤ 7,900 BTU/bhp-hr[2, 3]

1 - Based on AP-42 (4/2000), Section 3.2.
2 - Based on loads ≥ 75%.
3 - Based on HHV

4. Turbines

The facility is proposing to install two 10,179-hp Solar Taurus 70-10802S natural gas-fired turbines at the Buffalo Creek Processing Plant. The BACT analysis for the turbines is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The proposed turbines will be subject to 40 CFR Part 60, NSPS, Subpart KKKK. The standards for natural gas-fired turbines with a maximum heat input greater than 50 MMBTUH and less than or equal to 850 MMBTUH which commence construction after February 18, 2005, is 25 ppmdv NO_X @ 15% O_2.

Step 1 - Identify Available Control Technologies
A review of previous BACT analyses was conducted to identify available control technologies for consideration. The search was conducted for turbines similar to the units being proposed. The database was queried for small (<25 MW) simple cycle turbines permitted from January 2005 to July 2010 for turbines operating under the same SIC Code. AQD review included all SIC Codes for similar operations. According to RBLC, the proposed turbines have the lowest emissions of NO_X, CO, and VOC in comparison with other turbines operating under SIC Code 1311 and 1321.

The proposed BACT for $PM_{2.5}$ is the burning of natural gas and good combustion with emissions based on AP-42 (4/2000), Section 3.1 for turbines (0.0066 lb/MMBTU). There were no BACT determinations for $PM_{2.5}$ on the RBLC. There were some BACT determinations for PM_{10} which were also based on the AP-42 emissions factor. Therefore, no further analysis was conducted.

The proposed BACT emission limit for VOC (25 ppmv UHC @ 15% O_2) is equivalent to the listed levels and type of control (no control). The AP-42 (4/2000), Section 3.1 factor for VOC from natural gas fired turbines is 0.0021 lb/MMBTU.

RBLC BACT Search Results for VOC

RBLC ID	SIC Code	Emission Rate		RBLC ID	SIC Code	Emission Rate	
		(lb/MMBTU)	(ppmdv)			(lb/MMBTU)	(ppmdv)
NV-0050	7011	0.024	17[1]	FL-0266	4911	0.0138[1, 2]	10[1]
WY-0067	1321	0.035[1]	25	CO-0059	4922	0.0041[1]	3
WY-0067	1321	0.069[1]	50	CO-0058	4922	0.0041[1]	3
AL-0251	4911	0.0068	5[1]	TX-0454	4922	0.0036[1]	3[1]
LA-0232	4922	0.033	25[1]	TX-0468	2869	0.0139[1]	10[1]
NV-0048	4925	0.0069	5[1]	NJ-0055	4922	0.0031	2[1]
MD-0035	4925	0.004[2]	3[1]	ID-0011		0.0031	2[1]
MD-0036	4911	0.003[2]	2[1]				

[1] – Estimated; [2] – Use of Oxidation Catalyst

The proposed BACT emission limit for CO (25 ppmv @ 15% O_2) is similar to the levels indicated and the control (no control) is equivalent to the types of controls installed on the turbines listed. The lowest emissions limit was based on installation of the Lowest Achievable Emission Rate (LAER) for the applicable non-attainment area and required installation of an oxidation catalyst.

RBLC BACT Search Results for CO

RBLC ID	SIC Code	Emission Rate (ppmdv)	RBLC ID	SIC Code	Emission Rate (ppmdv)
NV-0050	7011	2.5 @ 15% O_2	AR-0075	2421	50.0 @ 15% O_2
NV-0048	4922	16.0 @ 15% O_2	WY-0059	4922	50.0 @ 15% O_2
CO-0058	4922	24.5 @ 15% O_2	AK-0062	1311	50.0 @ 15% O_2
CO-0059	4922	25.0 @ 15% O_2			

The proposed BACT emission limit for NO_X (15 ppmv @ 15% O_2) is similar to the levels indicated and the control (LBC) is equivalent to the types of controls installed on the turbines listed. The lowest emissions limit was based on a special LBC offered by Solar the SoloNO_X burner system.

RBLC BACT Search Results for NO_X

RBLC ID	SIC Code	Emission Rate (ppmdv)	RBLC ID	SIC Code	Emission Rate (ppmdv)
NV-0050	7011	5.0 @ 15% O_2	WA-0297	4924	25.0 @ 15% O_2
AR-0075	2421	14.0 @ 15% O_2	WA-0297	4924	25.0 @ 15% O_2
LA-0232	4922	15.0 @ 15% O_2	NV-0048	4922	25.0 @ 15% O_2
CO-0059	4922	15.0 @ 15% O_2	WA-0316	4923	25.0 @ 15% O_2
LA-0232	4922	15.0 @ 15% O_2	WY-0059	4922	25.0 @ 15% O_2
FL-0266	4911	20.0 @ 15% O_2	CO-0058	4922	48.0 @ 15% O_2
WA-0316	4923	25.0 @ 15% O_2	AK-0062	1311	85.0 @ 15% O_2

Step 2 - Eliminate Technically Infeasible Options
None of the control technologies were eliminated as technically infeasible.

Step 3 - Rank Control Technologies by Control Effectiveness (NO_X, CO & VOC)
The next step is to rank control technologies not eliminated due to technical infeasibility in order of decreasing effectiveness. SCR has been eliminated due to technical infeasibility; however, it has been evaluated further to demonstrate the economic feasibility of the technology.

Ranking of Control Technologies by Effectiveness

Pollutant	Control Technology	Control Level
NO_X	Selective Catalytic Reduction (SCR)	2.5 ppmdv @ 15% O_2
	Ultra Dry-Low NO_X Combustion (UDLN)	5.0 ppmdv @ 15% O_2
	Dry-Low NO_X Combustion (DLN)	15.0 ppmdv @ 15% O_2
CO	Oxidation Catalyst	2.5 ppmdv @ 15% O_2
	Dry-Low NO_X Combustion (DLN)	25.0 ppmdv @ 15% O_2
VOC	Oxidation Catalyst	2.5 ppmdv @ 15% O_2
	Dry-Low NO_X Combustion (DLN)	25.0 ppmdv @ 15% O_2

Step 4 - Evaluate Most Effective Controls Based on Impacts (NO_X, CO & VOC)
The economic feasibility of SCR was evaluated. The result was that the reduction in NO_X emissions using SCR is not economically feasible based on overall cost estimates and incremental reduction of emissions from the proposed emission limit (15 ppmdv @ 15% O_2) as shown below.

The cost for the initial purchase and installation of the SCR and ammonia or urea reagent for the SCR is approximately $588,695 for the turbines. Ammonia or urea must be continually purchased for use in the injection system. The cost of urea is approximately $13,334 per year depending on the current market price for urea at the time of purchase. The SCR catalyst and other process elements must be cleaned after 5 years of use. A comparison table of the cost estimates for additional reductions from a SCR added to a LBC turbine and a LBC turbine are presented below.

SCR VS LBC Cost Comparison for Solar Taurus 70-10802S Turbines

Factor	SCR	LBC
Total Capital Investment	$588,695	$ 0
Total Direct Annual Cost	$124,903	$ 0
Total Indirect Annual Cost	$247,871	$ 0
Total Annualized Cost	$372,774	$ 0
Design Control Efficiency	83%	60%
Tons NO_X Removed per Year	17.3	
Cost Effectiveness per Ton of NO_X Removed	$21,537	N/A

Cost Analysis for Oxidation Catalyst for Control of CO

Factor	CO
Total Capital Investment	$358,425
Total Direct Annual Cost	$108,443
Total Indirect Annual Cost	$65,369
Total Annualized Cost	$108,443
Design Control Efficiency	90%
Tons Removed per Year	19.0
Cost Effectiveness per Ton Removed	$5,708

Cost Analysis for Oxidation Catalyst for Control of VOC

Factor	VOC
Total Capital Investment	$358,425
Total Direct Annual Cost	$108,443
Total Indirect Annual Cost	$65,369
Total Annualized Cost	$108,443
Design Control Efficiency	90%
Tons Removed per Year	4.4
Cost Effectiveness per Ton Removed	$24,646

Step 5 - Select BACT and Document the Selection as BACT (NO_X, CO & VOC)

The additional cost of the SCR system is too high and is not warranted or justified for the turbines at this facility based on the relatively low additional reduction in NO_X emissions. Due to economic infeasibility of SCR, the technology has been eliminated as BACT for the proposed turbines at this facility. Natural gas-fired DLN turbines without add-on controls for NO_X can meet or exceed a NO_X emission limit that is equivalent to the NSPS, Subpart KKKK requirements of 25 ppmdv @ 15% O_2. The DLN combustion technology is a low emission technology and is already integrated into the proposed turbines as purchased. Thus, this technology does not result in any additional costs beyond the cost of the initial purchase and the normal operation and maintenance of the turbine. Therefore, the proposed BACT is no add-on controls for the DLN turbines with a manufacturer's emission guarantee for the proposed turbines of 15 ppmdv @ 15% O_2.

The additional cost of an oxidation catalyst is too high and is not warranted or justified for the turbines at this facility. Due to economic infeasibility of an oxidation catalyst, the technology has been eliminated as BACT for the proposed turbines at this facility. Therefore, the proposed BACT is no add-on controls for the turbines with a manufacturer's emission guarantee for the proposed turbines of 25 ppmdv CO @ 15% O_2 and 25 ppmdv VOC @ 15% O_2. The proposed BACT for $PM_{2.5}$ is the burning of natural gas. The proposed BACT for the 10,179-hp Solar Taurus 70-10802S turbines is summarized below.

Additional Review for Greenhouse Gases (CO_{2e})

Because geologic sequestration has been eliminated as a control option due to technical infeasibility, and because this engines already burn natural gas, the only remaining control option to consider is efficiency. Based on the mechanical drive portion of the turbines, the efficiency of the turbines is estimated at 33.7%. Additional greenhouse gas reductions and increased efficiency will be achieved by use a heat exchanger to recover heat from the turbine exhaust to heat oil for use elsewhere in the plant. The facility will not use duct burners so the turbines are not considered combined cycle turbines.

Summary of Proposed BACT for Turbines

Pollutant	Control Technology	Proposed Emission Level
NO_X	Dry-Low NO_X Combustion	15 ppmdv @ 15% O_2
CO	Efficient Design & Combustion	25 ppmdv @ 15% O_2
VOC	Efficient Design & Combustion	25 ppmdv @ 15% O_2
$PM_{2.5}$	Natural Gas Combustion	6.6E-03 lb/MMBTU[1]
CO_{2e}	Efficient Design & Combustion	≤ 8,220 BTU/bhp-hr[2, 3]

[1] - Based on AP-42 (4/2000), Section 3.1.
[2] - Based on loads ≥ 75%.
[3] - Based on LHV

5. <u>Heater</u>

The facility is proposing to install an 11.04 MMBTUH regeneration heater at the Buffalo Creek Processing Plant. The BACT analysis for the heater is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The proposed heater will be subject to 40 CFR Part 60, NSPS, Subpart Dc. Since the proposed heater burns natural gas as fuel, it is not subject to any emission standards under this subpart.

Step 1 - Identify Available Control Technologies

A review of previous BACT analyses was conducted to identify available control technologies for consideration. The search was conducted for heaters similar to the unit being proposed. The applicant queried the database for commercial/institutional-size (<100 MMBTUH) boilers/furnaces permitted from January 2005 to July 2010 operating under the same SIC Code. AQD review included all SIC Codes for similar operations but limited to the same size range as the applicable heater. According to RBLC, the proposed heater has the lowest emissions of NO_X and CO in comparison with other heaters operating under SIC Codes 1311 and 1321. The search results for NO_X and CO emissions for heaters/boiler rated at ~10 MMBTUH are summarized below.

The proposed BACT for CO_{2e}, VOC, and $PM_{2.5}$ is the burning of natural gas and good combustion with emissions based on AP-42 (7/1998), Section 1.4 for heaters. There were some BACT determinations for VOC and PM_{10} but they were based on the AP-42 emissions factors. Therefore, no further analysis was conducted for these pollutants.

RBLC Search Results for NO_X and CO

RBLC ID	SIC Code	Emission Rate (lb/MMBTU)	RBLC ID	SIC Code	Emission Rate (lb/MMBTU)
NO_X			CO		
NV-0047	9711	0.0300	NV-0047	9711	0.0370
NV-0049	7011	0.0353	NV-0049	7011	0.0705
NJ-0062	4911	0.0360	NJ-0062	4911	0.1500
WI-0207	2869	0.0400	WI-0207	2869	0.0800
IA-0068	4911	0.0490	IA-0068	4911	0.0820
AR-0076	2899	0.0510	AR-0076	2899	N/A
AR-0090	3312	0.0750	AR-0090	3312	0.0840
IA-0063	4911	0.0950	IA-0063	4911	N/A
TX-0364	1321	0.0600	TX-0364	1321	0.0990
AK-0062	1311	0.0800	AK-0062	1311	0.1500
WY-0066	1311	0.0500	WY-0066	1311	0.0800

The proposed BACT emission limit for NO_X (0.045 lb/MMBTU) is equivalent to the listed levels and type of control (LNB) and no further analysis was conducted. Some of the lower emission limits include flue gas recirculation and ultra LNB. However, for a heater of this size the proposed emission limit is acceptable as BACT.

The proposed BACT emission limit for CO (0.074 lb/MMBTU) is similar to the levels indicated and the control (no control) is equivalent to the types of controls installed on the heaters listed and no further analysis was conducted.

Considerations for GHG

Because geologic sequestration has been eliminated as a control option due to technical infeasibility, and because this emission unit already burns natural gas, the only remaining control option to consider is efficiency. The heater proposed for this project is designed for 80% efficiency. BACT for this unit is natural gas combustion and good design and combustion practices. No further analysis was conducted for GHG.

Step 5 - Select BACT and Document the Selection as BACT (NO_X, CO & VOC)

The proposed BACT is summarized below and no further analysis was conducted.

Summary of Proposed BACT for Heater

Pollutant	Control Technology	Proposed Emission Level
NO_X	Low NO_X Burners	0.045 lb/MMBTU
CO	Good Combustion Practices	0.074 lb/MMBTU
VOC	Good Combustion Practices	0.00539 lb/MMBTU[1]
PM	Natural Gas Combustion	0.00745 lb/MMBTU[1]
CO_{2e}	Natural Gas Combustion	117 lb/MMBTU[1]

[1] - Based on AP-42 (7/1998), Section 1.4.

6. Amine Unit Still Vent/Acid Gas Flare

The facility is proposing to install a 230 MMSCFD Amine Unit at the Buffalo Creek Processing Plant. The amine unit is equipped with a reboiler for regeneration of the amine. The off-gases from the reboiler (Amine Unit Still Vent) are routed to the Acid Gas Flare. The waste gases combusted in the Acid Gas Flare are estimated at 10 MMBTUH. The BACT analysis for the flare is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The Acid Gas Flare is a control device for control of emission of H_2S. The flare will also control emissions of CH_4 and VOC. The emissions of NO_X, CO, $PM_{2.5}$, and CO_{2e} are the result of combustion of the H_2S, CH_4, and VOC. Sizing of the flare is an important aspect in the control of H_2S, CH_4, and VOC. As BACT for the Amine Unit Still Vent/Acid Gas Flare, the AQD is proposing compliance with manufacturer operating and maintenance procedures and the requirements of 40 CFR Part 60, §60.18.

Considerations for GHG

The primary purpose of the amine treating process is to remove CO_2 and H_2S from the natural gas liquids produced at the plant. As such, emissions of CO_2 from this vent are unavoidable. A thermal oxidizer is included as an end-of-stack control to destroy H_2S, which is acutely toxic, and which is necessary to meet Oklahoma DEQ H_2S emission requirements, but does nothing to reduce CO_2 emissions because it is non-combustible. The thermal oxidizer burns natural gas in order to destroy the H_2S, which produces a relatively small amount of CO_2 compared to the quantity necessarily emitted from the vent due to the treating process. Because geologic sequestration has been eliminated as a control option due to technical infeasibility, and because this emission unit already burns natural gas (in the thermal oxidizer), the only remaining control option to consider is efficiency.

The vast majority of the CO_2 that is emitted from the vent is necessary due to the fundamental purpose of the treater, a reduction in natural gas combustion will have a small impact on GHG emissions. Accordingly, no further emission reductions are considered feasible. Features will be installed on the thermal oxidizer to make it energy efficient. It includes a "cold-wall" design to mitigate thermal radiation from the sidewalls and stack and a precipitation shield to maintain temperature during rain storms. Accordingly, combustion of natural gas in the thermal oxidizer, and following manufacturer operating and maintenance procedures, is proposed as BACT.

7. Main Plant Flare

The facility is proposing to install a flare at the Buffalo Creek Processing Plant. The flare will be used to control CH_4 and VOC emissions from venting of gases from the gas plant. The waste gases combusted in the Main Plant Flare are estimated at 1 MMBTUH. The BACT analysis for the flare is for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The Main Plant Flare is a control device for control of emissions of CH_4 and VOC. The emissions of NO_X, CO, $PM_{2.5}$, and CO_{2e} are the result of combustion of the CH_4 and VOC. Sizing of the flare is an important aspect in the control of CH_4 and VOC. The flare is subject to NSPS, Subparts A and KKK. As BACT for the Main Plant Flare, the AQD is proposing compliance with manufacturer operating and maintenance procedures and the requirements of 40 CFR Part 60, §60.18. By combusting the potentially released CH_4, operation of the flare will actually reduce the CO_{2e} emissions from venting of CH_4 from the facility by 20 times.

8. Produced Water Storage Vessels

The facility is proposing to install six 200-barrel produced water storage vessels at the Buffalo Creek Processing Plant. The BACT analysis for the produced water storage vessels is for VOC and CO_{2e}. BACT for the produced water storage vessels are no add on controls at an emission rate of 1.93 lb/10^3 gallons.

9. Condensate Truck Loading

The facility is proposing to install a condensate truck loading station at the Buffalo Creek Processing Plant. The BACT analysis for the condensate loading operations is for VOC and CO_{2e}. Control of the loading operations using vapor balancing is proposed as BACT for VOC and CO_{2e} at an emission rate of 1.60 lb/10^3 gallons.

10. Fugitive Equipment Leaks

The facility will have fugitive equipment leaks related to operation of the Buffalo Creek Processing Plant. The BACT analysis for the fugitive equipment leaks is for VOC and CO_{2e}. Compliance with leak detection and repair regulations, as specified in 40 CFR Part 60, Subpart OOOO, for VOC control, is proposed as BACT for VOC and CO_{2e}.

11. Blowdowns

The facility will have blowdowns as part of the facility startup and shutdown procedures at the Buffalo Creek Processing Plant. The BACT analysis for blowdowns is for VOC and CO_{2e}. Emissions are less than 10 TPY of VOC and 1 TPY of CO_{2e}. BACT for this activity are no add on controls and limiting the permitted blowdowns to 1.44 MMSCFY.

C. Ambient Air Impact Analysis

If a source has the potential to emit a pollutant above the PSD significance levels then they trigger an air quality impact evaluation. The evaluation includes atmospheric dispersion modeling for the following pollutants for which the PSD significance emission rates will be exceeded:

- Nitrogen Oxides, NO_X
- Carbon Monoxide, CO
- Particulate Matter, $PM_{2.5}$
- Ozone, O_3

If the maximum predicted concentrations due to the project emission increases (proposed modification) exceed the significant impact levels (SIL) a radius of impact is established and the facility has to conduct refined modeling to include all sources within 50 km of the radius of impact to verify compliance with the following air quality standards:

- National Ambient Air Quality Standards (NAAQS), and
- Class II Area PSD Increments, and
- Class I Area PSD Increments, for any Class I area within 300 km of the facility.

EPA regulates VOC and NO_X as precursors to tropospheric ozone formation. Ozone is unique because the EPA has not established a PSD modeling significance level (an ambient concentration expressed in either $\mu g/m^3$ or ppmv) for ozone. However, EPA has established an ambient monitoring *de minimis* level, which is different from other criteria pollutants, because it is based on a mass emission rate (100 TPY) instead of an ambient concentration (in units of $\mu g/m^3$ or ppmv). Ozone is reviewed in the Monitoring section.

This modeling analysis follows the Oklahoma Air Quality Division Modeling Section (AQD) guidance document "Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits", April 2011.

1. Model

The steady-state dispersion model, AERMOD (11353), was used to predict all off property impacts from the facility. The AERMOD model was selected based on several factors. The selection factors include:

- acceptance by the EPA and many state agencies
- ability to handle flat, intermediate, and complex terrain
- ability to incorporate building downwash into the predicted concentrations
- ability to apply several different averaging periods, including annual.

Even though EPA has released a newer version of the AERMOD model the revisions did not affect any of the modeling that was conducted by the applicant. The AQD review of the modeling conducted by the applicant was conducted using the most recent release of the model (Version 12060).

2. Nearby Source Inventory

The NO_X, CO, and $PM_{2.5}$ nearby source parameters and potential emission rates out to 50 km were provided by the AQD and were incorporated into the NAAQS modeling analyses.

3. Dispersion Model Options

The AERMOD model was used in the modeling analysis and includes many options that can be selected by the user to adapt to many different modeling situations. The modeling options selected for this analysis are summarized on below.

i) Downwash Analysis

The wind blowing around a building creates zones of turbulence that is greater than if the building were absent. The EPA Building Profile Input Program (BPIP-Prime) was used to estimate the downwash effects of the compressor buildings. The latest BPIP-Prime program (version 04274) was used for these calculations.

The four Caterpillar 3608 LE and six Caterpillar 3606LE compressor engines will be located in separate buildings separated by only a few feet. Each of the compressor engine stacks have vertical unobstructed releases.

ii) Land Use

Based on an evaluation of the United States Geologic Service (USGS) 1:24,000 scale maps for the area including the facility, the predominant land use is rural. Therefore, rural dispersion coefficients were used for all modeling.

iii) Receptor Grid

A series of nested receptor grids composed of several different spaced receptors was employed in the modeling analysis. After the plant boundary dimensions were determined, receptors were spaced outward as follows: 100 m out to 1 km, 250 m out to 2.5 km, 500 m out to 5 km, 750 m out to 7.5 km, and finally 1 km out to 10 km.

iv) Terrain Data

The following USGS 7.5 min DEM terrain data were included in the modeling analysis: Prentiss, Mayfield, Grimes, Sweetwater, Baker Lake, Doxey, Sayre, and Berlin.

v) Meteorological Data

Five years of meteorological data (2006, 2007, 2008, 2009, and 2010) from Eric, Oklahoma were utilized in this analysis. These data sets were obtained from the AQD.

4. Significant Impact Modeling Analysis Results

The results of the modeling impacts were compared to the applicable significant impact levels (SIL) to determine if cumulative modeling analysis was required for each pollutant averaging period.

Pollutant	Averaging Period	SIL $\mu g/m^3$	Impacts[1] $\mu g/m^3$	≥ SIL
CO	1-hour	2,000	287	NO
	8-hour	500	170	NO
$PM_{2.5}$	24-hour	1.2	5.7	YES
	Annual	0.3	0.7	YES
NO_2	1-hour	7.5	68.4	YES
	Annual	1.0	5.2	YES

[1] - Based on the Maximum Impact or Highest 1st High.

This project resulted in ambient impacts above the SIL for the $PM_{2.5}$ 24-hour, $PM_{2.5}$ Annual, NO_X 1-hour, and NO_X Annual standards. Therefore, the applicant performed refined modeling for these pollutants and averaging periods. The refined modeling included a review of the NAAQS and Increment modeling. The NAAQS modeling included background monitoring data.

5. Monitoring Data

i) Comparison of Impacts with Monitoring Significance Levels

Pollutant	Averaging Period	MSL $\mu g/m^3$	Impacts[1] $\mu g/m^3$	≥ MSL
$PM_{2.5}$	24-hour	4.0	5.7	YES
NO_2	Annual	14	5.2	NO

[1] - Based on the Maximum Impact or Highest 1st High.

Available monitoring data is acceptable because it is "within the time period that maximum pollutant concentrations would occur" and is complete and adequate enough to determine if the facility will cause or contribute to a violation of the NAAQS.

ii) Background Data for NAAQS Analysis

Pollutant	Averaging Period	Design Value $\mu g/m^3$	Monitor(s)	Year(s)
$PM_{2.5}$	24-hour	24.6	40-015-9008	2009-2011
	Annual	9.2	40-015-9008	2009-2011
NO_2	1-hour	38.5	40-(001 & 135)	2009-2011
	Annual	29.5	40-109-1037	2011

iii) Ozone (O_3)

Pre-construction monitoring for ozone is required for any new source or modified existing source located in an unclassified or attainment area with greater than 100 tons per year of VOC or NO_X emissions. Continuous ozone monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification.

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 this requirement. The existing monitoring data should be representative of three types of areas: (l) the location(s) of maximum concentration increase from the proposed source or modification, (2) the location(s) of the maximum air pollutant concentration from existing sources, and (3) the location(s) of the maximum impact area, i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of existing sources and the proposed new source or modification.

The locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas and contributing sources. In situations where there is no existing monitor in the modeled areas, monitors located outside these three types of areas may be used. Each determination must be made on a case-by-case basis. The EPA guidance on this issue is not designed for the evaluation of a secondary pollutant like ozone and the guidance document clearly discusses the evaluation of the impact of primary pollutants. However, a demonstration that existing monitoring data for ozone is representative of the three areas listed above can be made.

The facility is located in a rural area, Beckham County, northwest of Sayre, Oklahoma, with a population density of 25 people per square mile. The emission density reflects a lack of population and industrial development. Based on the most recent triennial emission inventory, the NO_X emission density for Beckham County is 3.6 tons per square mile. The VOC emission density is 4.7 tons per square mile. There are no other major sources of NO_X or VOC within 20 km of the facility. The terrain is flat. The nearest ozone monitors are in Caddo County (ID 400159008), 131 km ESE of the facility and Dewey County (ID 400430860) 113 km NE of the facility. These monitors are located in similarly rural areas, with similar emission densities, climate, and terrain.

O_3 Monitoring Data

Monitor	2009 4th High	2010 4th High	2011 4th High	Design Value
400430860	67 ppb	67 ppb	78 ppb	71 ppb
400159008	64 ppb	69 ppb	84 ppb	72 ppb

Projected emissions are 131 TPY of VOC and 154 TPY of NO_X. Given source parameters, local emission densities, and baring the likelihood of ozone scavenging, any resultant O_3 concentration increases are likely to be near the facility and nominal. The existing regional monitors are adequate to establish existing ozone concentrations for the facility and its impact area. Given emission levels from the facility and local emission inventories no further analyses were warranted.

6. Refined Modeling Analysis Results

i) $PM_{2.5}$

Based on EPA's guidance "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" dated March 23, 2010, the five year average of the modeled highest 1st high 24-hour average impact was used to demonstrate compliance with the 24-hour standard and the five year average annual maximum modeled impacts was used to demonstrate compliance with the annual standard. The modeled impacts were added to the background to demonstrate compliance with the NAAQS. All sources were assumed to be increment consuming sources.

NAAQS Compliance Demonstration

Pollutant	Averaging Period	Design Value µg/m^3	Impacts µg/m^3	Total µg/m^3	NAAQS µg/m^3
$PM_{2.5}$	24-hour	24.6	7.2	31.8	35
	Annual	9.2	0.8	10.0	15

Class II Increment Compliance Demonstration

Pollutant	Averaging Period	Impacts $\mu g/m^3$	Increment $\mu g/m^3$
$PM_{2.5}$	24-hour	7.2	18
	Annual	0.8	8

The facility was significant for NO_X precursors (> 40 TPY) for the formation of secondary $PM_{2.5}$. Since the H1H was used to model compliance with the NAAQS rather than the H8H, the difference between the two values is what was assigned to the secondary formation of $PM_{2.5}$ within the modeling domain. Based on the difference between these two values secondary formation from the facility was attributed 1.8 $\mu g/m^3$. If we assume a conservative NO_3/NO_X ratio of 1:100, then secondary formation of $PM_{2.5}$ would amount to approximately 1.4 TPY which would have an estimated impact of 0.8 $\mu g/m^3$ which is accounted for by using the H1H rather than the design value form the modeling. Also, since the maximum impact in the modeling domain, which occurs at the facility fenceline, is used to determine compliance with the NAAQS for the whole domain, and secondary formation is expected to occur much farther from the facility the analysis of secondary formation using the H1H is adequate enough to account for secondary formation of PM2.5 from the proposed facility.

The main impacts from the direct $PM_{2.5}$ emissions occurred at the fenceline of the property and the impacts from the modeled emissions decreased by 96% within 10 km of the facility. The maximum impacts from the formation of secondary $PM_{2.5}$ will likely occur significantly outside of the modeling domain where the impacts from the primary $PM_{2.5}$ will have significantly decreased.

Available monitoring data was complete and adequate enough to account for formation of secondary $PM_{2.5}$ emissions because it is "within the time period that maximum pollutant concentrations would occur" and within a similar rural area with similar emission densities, climate, and terrain. Not to mention that some consideration should be given to the potential for some double counting of the impacts from modeled emissions that may be reflected in the background monitoring.

Given emission levels from the facility and local emission inventories no further analyses of secondary formation were warranted.

ii) <u>NO_2</u>

NO_2 modeling is usually done in Tiers. The first Tier is 100% conversion of NO_X to NO_2. The second Tier utilizes the Ambient Ratio Method which predicts 80% conversion of NO_X to NO_2. The third Tier is a case-by-case analysis of NO_X conversion utilizing either the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM). In these methods, the in-stack ratio of NO_X to NO_2 is utilized to help determine the total conversion of NO_X to NO_2. A facility can use all of methods mentioned above or just one of those methods to determine facility impacts for the SIL, NAAQS, and Increment. Modeling for the new 1-hour standard should comply with the EPA's guidance "General Guidance for Implementing the 1-hour NO_2 NAAQS in PSD permits, Including the Interim 1-hour NO_2 SIL" dated June 28, 2010. Modeling for the annual NAAQS and Increment are still required since these standards have not been vacated.

The facility did not show compliance using Tier I or Tier II analyses. Therefore, compliance with the 1-hour NAAQS was done utilizing a Tier III analysis and PVMRM. The Tier III analysis required a modeling protocol and pre-approval. The protocol was submitted to EPA on March 6, 2012, by AQD. The protocol was approved by AQD.

In the original modeling submittal, an in-stack ratio of 0.2 was used for all sources and all of the modeled impacts plus background were below the 1-hour NO_2 NAAQS (188 µg/m^3). The equilibrium ratio was set at 0.9. For the PVMRM analysis, hourly ozone data from the area is input into AERMOD which it then uses to predict the conversion of NO_X to NO_2. The ozone data was the hourly data from the nearest ozone monitor located in Seiling, Oklahoma and was from the same years as those for the modeling. For the increment analysis, all sources were assumed to be increment consuming sources. For the revised Tier III analysis conducted by AQD, the in-stack ratio for each source was evaluated and set at the levels listed below.

In-Stack NO_2/NO_X Ratios

Source Type	**Ratio**
4SLB Engines	0.35
2SLB Engines	0.50
4SRB Engines	0.05
Turbines	0.20
Heaters/Boilers	0.10

Using the revised in-stack ratios, the modeled impacts of the nearby sources plus background did exceed the 1-hour NO_2 NAAQS. The list of violations and impacts from the nearby sources and the proposed source is shown below. Based on the modeling analysis, the impacts from the proposed facility did not cause or contribute to a violation of the NAAQS. Impacts from the proposed facility, at the receptors where a violation was predicted, were significantly below the interim significant impact level (7.5 µg/m^3). After the 13th highest high there were no more predicted violations of the NAAQS.

NAAQS Compliance Demonstration

Pollutant	**Averaging Period**	**Design Value µg/m^3**	**Impacts µg/m^3**	**Total µg/m^3**	**NAAQS µg/m^3**
NO_2	1-hour	38.5	185	169.4	188
	Annual	29.5	7.7	37.2	100

Predicted Violations of the NAAQS and Impacts of BCGPP

X	Y	CONC	BCGPP	RANK	X	Y	CONC	BCGPP	RANK
(m)	(m)	(μg/m^3)	(μg/m^3)		(m)	(m)	(μg/m^3)	(μg/m^3)	
427433.6	3910057	152.2270	0.00068	8TH	434600.3	3907474	154.6877	0.00174	9TH
433766.9	3914279	151.2639	0.00356	8TH	435433.6	3912335	162.0195	0.00345	9TH
433766.9	3910390	150.9974	0.00428	8TH	435433.6	3911362	155.2488	0.00636	9TH
433766.9	3909418	154.3952	0.00334	8TH	435433.6	3910390	160.5962	0.00408	9TH
433766.9	3908446	158.7000	0.00432	8TH	435433.6	3909418	174.7161	0.00407	9TH
434600.3	3913307	161.7900	0.00605	8TH	435433.6	3908446	181.2005	0.00475	9TH
434600.3	3912335	149.8912	0.00340	8TH	435433.6	3907474	156.2307	0.00483	9TH
434600.3	3911362	162.3923	0.00337	8TH	434600.3	3910390	156.5977	0.00371	10TH
434600.3	3910390	174.0657	0.00490	8TH	434600.3	3909418	163.3296	0.00458	10TH
434600.3	3909418	173.2539	0.00590	8TH	434600.3	3907474	149.5572	0.00378	10TH
434600.3	3907474	157.6205	0.00528	8TH	435433.6	3912335	154.7232	0.00182	10TH
435433.6	3913307	153.2717	0.00440	8TH	435433.6	3910390	157.9572	0.00428	10TH
435433.6	3912335	170.5954	0.00352	8TH	435433.6	3909418	162.0428	0.00628	10TH
435433.6	3911362	157.4510	0.00614	8TH	435433.6	3908446	171.6604	0.00247	10TH
435433.6	3910390	170.3900	0.00434	8TH	434600.3	3910390	150.8002	0.00085	11TH
435433.6	3909418	182.2412	0.00212	8TH	434600.3	3909418	154.4222	0.00246	11TH
435433.6	3908446	184.8552	0.00365	8TH	435433.6	3910390	151.4281	0.00418	11TH
435433.6	3907474	162.7098	0.00661	8TH	435433.6	3909418	156.1174	0.00486	11TH
433766.9	3909418	150.3985	0.00573	9TH	435433.6	3908446	163.5977	0.00513	11TH
433766.9	3908446	152.6667	0.00356	9TH	434600.3	3909418	151.4059	0.00374	12TH
434600.3	3913307	153.6835	0.00254	9TH	435433.6	3909418	151.3350	0.00397	12TH
434600.3	3911362	157.5146	0.01007	9TH	435433.6	3908446	152.9536	0.00616	12TH
434600.3	3910390	162.2392	0.00676	9TH	435433.6	3908446	150.6407	0.00697	13TH
434600.3	3909418	166.8251	0.00319	9TH					

Increment Compliance Demonstration

Pollutant	Averaging Period	Impacts μg/m^3	Increment μg/m^3
NO_2	Annual	7.7	25

D. Additional Impacts Analysis

An additional impacts analysis considering existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area was performed and the following are addressed:

- Class I Area Impacts
- Class II Area Visibility Impacts
- Growth Impacts

- Soil and Vegetation Impacts

1. Class I Area Impacts 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 119 km northwest of the Wichita Mountain Wildlife Class I area.

The following is an excerpt from the Federal Land Managers' Air Quality Related Values Work Group (Flag), Phase I Report – Revised (2010), Section 3.2 Initial Screening Criteria (New):

> *"…the Agencies will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_X, PM_{10}, and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions), divided by the distance (in km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources."*

The total emissions for SO_2, NO_X, PM_{10}, and H_2SO_4 at the facility are 200 TPY. Therefore, the Q/D value is 1.8 which is less than 10 and no further Class I AQRV impacts analyses are required.

For compliance with the Class I area increments, the maximum impacts at the closest receptor in the direction of the Class I area, 14 km southeast of the facility and approximately 105 km northwest of the Class I area, was taken and compared to the Increment.

Class I Increment Compliance Demonstration

Pollutant	Averaging Period	Impacts µg/m^3	Increment µg/m^3
$PM_{2.5}$	24-hour	0.07	2.0
	Annual	0.01	1.0
NO_2	Annual	0.88	2.5

2. Class II Area Visibility Impacts Analysis

Per the referenced AQD guidance document, sources within 40 km of a Class II Sensitive area shall use the VISCREEN model to address the visibility impacts within the Class II Sensitive area. The facility is approximately 21 km south of the Black Kettle National Grassland. Therefore, VISCREEN was used to determine the visibility impacts from the facility at the Black Kettle National Grassland. The maximum visual impacts from the facility are below the screening criteria as shown below.

VISCREEN Output

					Delta E		Contrast	
Background	**Theta**	**Azi**	**Distance**	**Alpha**	**Criteria**	**Plume**	**Criteria**	**Plume**
SKY	10	145	28.5	24	2.0	1.3	0.05	-0.002
SKY	140	145	28.5	24	2.0	0.5	0.05	-0.007
TERRAIN	10	84	20	84	2.0	0.4	0.05	0.004
TERRAIN	140	84	20	84	2.0	0.1	0.05	0.002

3. Growth Impact Analysis

A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth resulting from the new facility. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. No additional residential and commercial/industrial growth will result from the new facility since the facility will be located in an area that has an available population to supply employees.

4. Soil & Vegetation Impacts Analysis

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH. It is expected that compliance with the primary and secondary NAAQS will ensure that emissions from the facility will not adversely affect vegetation or soils in the surrounding area.

SECTION V. EMISSIONS

A. N.E. Mayfield (NEM) Gas Plant (Existing)

Normal Operation

Facility-Wide Criteria Pollutant Emissions for NEM from Permit No. 2009-276-TVR2

	NO_X		CO		VOC	
Emission Unit	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
E-TEGDEHY	0.22	0.96	0.18	0.81	0.01	0.05
E-SELECTOX	0.93	4.08	0.78	3.43	0.05	0.22
E-REGENHTR1	3.10	13.57	2.60	11.40	0.17	0.75
E-GASTRAIN1	---	---	---	---	---	---
C-FLARE1	151.19	---	1,296.51	---	330.21	---
FUG	---	---	---	---	---	5.71
Total Emissions	**155.44**	**18.61**	**1,300.07**	**15.64**	**330.44**	**6.73**

Facility-Wide Criteria Pollutant Emissions for NEM from Permit No. 2009-276-TVR2

	SO_2		$PM_{10}/PM_{2.5}$		CO_{2e}[3]	
Emission Unit	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
E-TEGDEHY	0.13	0.56	0.02	0.07	262	1,147
E-SELECTOX	0.54	2.37	0.07	0.31	1,112	4,869
E-REGENHTR1	1.80	7.89	0.24	1.03	3,697	16,194
E-GASTRAIN1	207.05	906.87	---	---	15,702	68,773
C-FLARE1	*3,764.49*	---	0.04	0.15	3,214	270
FUG	---	---	---	---	---	1,095
Total Emissions	**3,974.02**	**917.73**	**0.37**	**1.56**	**23,987**	**92,348**

[3] - Mainly CO_2 except for fugitives which are mostly CH_4.

Alternative Operating Scenario (AOS)

Facility-Wide Criteria Pollutant Emissions for NEM from Permit No. 2009-276-TVR2

	NO_X		CO		VOC	
Emission Unit	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
E-TEGDEHY	0.22	0.96	0.18	0.81	0.01	0.05
E-SELECTOX *	---	---	---	---	---	---
E-REGENHTR1	3.10	13.57	2.60	11.40	0.17	0.75
E-GASTRAIN1 *	---	---	---	---	---	---
C-FLARE1	1.02	4.48	8.76	38.38	2.23	9.78
FUG	---	---	---	---	---	5.71
Total Emissions	**4.34**	**19.01**	**11.54**	**50.59**	**2.41**	**16.29**

* Down during alternative operating scenario.

Facility-Wide Criteria Pollutant Emissions for NEM from Permit No. 2009-276-TVR2

	SO_2		$PM_{10}/PM_{2.5}$		CO_{2e} [3]	
Emission Unit	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
E-TEGDEHY	0.13	0.56	0.02	0.07	262	1,147
E-SELECTOX *	---	---	---	---	---	---
E-REGENHTR1	1.80	7.89	0.24	1.03	3,697	16,194
E-GASTRAIN1 *	---	---	---	---	---	---
C-FLARE1	3.80	16.65	0.04	0.15	---	270
FUG	---	---	---	---	---	1,095
Total Emissions	**5.73**	**25.10**	**0.30**	**1.25**	**3,959**	**18,706**

* Down during alternative operating scenario.

[3] - Mainly CO_2 except for fugitives which are mostly CH_4.

B. Buffalo Creek Processing Plant (BCPP) (New)

All CO_{2e} emissions from combustion of natural gas are based on the default factors for natural gas combustion from 40 CFR Part 98, Subpart C, Tables C-1 and C-2 and the related global warming potential factors from 40 CFR Part 98, Subpart A, Table A-1 (A combined CO_{2e} emission factor of 117 lb/MMBTU). All other CO_{2e} emissions are related to CO_2 or CH_4 emissions and the related global warming potential factor. Emissions estimates for the engines are based on manufacturer's emission data for NO_X, CO and VOC, AP-42 (8/2000), Section 3.2 emission factors for $PM_{10/2.5}$, and continuous operation.

Engine Emission Factors

Name/Model	NO_X (g/hp-hr)	CO (g/hp-hr)	VOC (g/hp-hr)
2,370-hp Caterpillar G3608LE W/OC	0.50	0.55	0.22
1,775-hp Caterpillar G3606LE W/OC	0.50	0.55	0.22

W/OC – with oxidation catalyst

Emission estimates from the turbines are based on manufacturer's emission data for NO_X, CO and VOC, AP-42 (4/2000), Section 3.1 emission factors for $PM_{10/2.5}$, and continuous operation.

Turbine Emission Concentrations

Pollutant	Concentration	lb/MMBTU[1]
NO_X	15.0 ppmvd @ 15% O_2	0.060
CO	25.0 ppmvd @ 15% O_2	0.061
VOC[2]	25.0 ppmvd @ 15% O_2	0.035

[1] – LHV based on highest heat input @ 0 ˚F; [2] - As Methane.

Emission estimates from the heater are based on manufacturer's data for NO_X and CO for the Low-NO_X burners, the rated heat input, and AP-42 (7/1998), Section 1.4 emission factors for VOC, $PM_{10/2.5}$, and SO_2, and continuous operation.

Heater Emission Factors

Size	NO_X (lb/MMBTU)	CO (lb/MMBTU)
11.04 MMBTUH	0.045	0.071

Off-gases from the amine unit's still vent and flash tank were estimated using ProMax Version 3.2.10286.0 (a process simulation program) a natural gas flow rate of 220 MMSCFD, a diethanolamine (DEA) solution (30%) flow rate of 120 gpm. The composition of the acid gas stream and flash tank stream were noted in the application. Emissions from the acid gases flare are based on a 100 % collection efficiency of the gases from the still vent and flash tank, a 98% combustion efficiency, the emission factors from AP-42 (1/1995), Section 13.5 for NO_X and CO, the emission factor from AP-42 (7/1998), Section 1.4 for $PM_{10/2.5}$, an annual throughput of waste gas of 338.7 MMSCF/year with a heat rating of 85 BTU/SCF and an annual throughput of 67.5 MMSCF/year of supplemental gas with a heat rating of 1,047 BTU/SCF.

Emissions from the main plant flare are based on an annual throughput of waste gas of 4.648 MMSCF/year with a heat rating of approximately 2,076 BTU/SCF, a throughput of flare pilot gas of 2.179 MMSCF/year with a heat rating of approximately 1,000 BTU/SCF, AP-42 (1/95), Section 13.5 factors for NO_X and CO and AP-42 (7/1998), Section 1.4 for $PM_{10/2.5}$, and SO_2 for combustion of the waste gas, and AP-42 (7/1998), Section 1.4 for combustion of the pilot gas.

No flashing emissions were estimated from the gas plant pressurized tanks or from the stabilized condensate tanks since the condensate is processed by a stabilizer prior to storage and all gases from the stabilization unit are vented through a closed system to the gas plant inlet. Working and breathing emission from the stabilized condensate storage tanks are based on a total throughput of 4,000 barrels/day split between all eight tanks, AP-42 (11/2006), Section 7.1, using TANKS4.0b, a 100% collection efficiency, and a 98% destruction efficiency because the tanks are vented to the main plant flare. Uncontrolled emissions from the stabilized condensate tanks are included in the emissions from the main plant flare.

Flashing emissions from the produced water storage vessels are based on an average factor of 10 SCF of vapor per barrel of produced water, 200 barrels per day of produced water, a molecular weight of 23.83, a VOC content of 12.34% by weight, a CO_2 content of 24.65% by weight, and a CH_4 content of 46.48% by weight. No working or breathing emissions are estimated from the produced water storage vessels because the condensate is separated out from the produced water prior to storage.

Emissions from loading stabilized condensate into tank trucks were estimated using AP-42 (1/95), Section 5.2, Equation 1, a saturation factor of 0.6. a vapor pressure of 5.67 psia, a vapor molecular weight of 65, a throughput of 61,320,000 gallons per year, a 70% collection efficiency for vapor balancing, and a 98% destruction efficiency because the tanks are vented to the main plant flare. Emissions from loading produced water into tank trucks were estimated using AP-42 (1/95), Section 5.2, Equation 1, a saturation factor of 0.6. a vapor pressure of 5.67 psia, a vapor molecular weight of 65, a throughput of 30,660 gallons per year or 1% of the total throughput as condensate.

Fugitive VOC emissions are based on estimated equipment counts, an estimated C_{3+} content, and average emission factors or emission screening values from EPA's *1995 Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017).

Emissions from blowdowns were estimated using an estimated volume of 1.44 MMSCFY, a molecular weight of 19.85, a VOC content of 16.978% by weight, a CO_2 content of 0.415% by volume, and a CH_4 content of 68.056% by weight.

Formaldehyde Emissions from the Engines & Turbines

			Factor	**%**	**Est. Emissions**	
EU	**Source**	**Hp**	**g/hp-hr**	**Reduction**	**lb/hr**	**TPY**
C-1-4	Caterpillar G3608LE W/OC	2,370	0.26	85	0.815	3.57
C-5-10	Caterpillar G3606LE W/OC	1,775	0.26	85	0.916	4.01
T-1 & 2	Solar Taurus 70-10802S	10,179	0.003	0	0.135	0.591
	Totals				**1.866**	**8.171**

W/OC - with oxidation catalyst

Facility-Wide Criteria Pollutant Emissions for BCPP[1]

	NO_X		CO		VOC	
Sources	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-1	2.61	11.44	2.87	12.59	1.15	5.03
C-2	2.61	11.44	2.87	12.59	1.15	5.03
C-3	2.61	11.44	2.87	12.59	1.15	5.03
C-4	2.61	11.44	2.87	12.59	1.15	5.03
C-5	1.96	8.57	2.15	9.43	0.86	3.77
C-6	1.96	8.57	2.15	9.43	0.86	3.77
C-7	1.96	8.57	2.15	9.43	0.86	3.77
C-8	1.96	8.57	2.15	9.43	0.86	3.77
C-9	1.96	8.57	2.15	9.43	0.86	3.77
C-10	1.96	8.57	2.15	9.43	0.86	3.77
T-1[2]	4.75	20.77	4.82	21.11	2.76	12.11
T-2[2]	4.75	20.77	4.82	21.11	2.76	12.11
H-1	0.50	2.18	0.82	3.58	0.06	0.26
FLARE-1	0.70	3.06	3.80	16.65	0.56	2.46
FLARE-2	---	0.35	---	1.80	---	3.55
PW1-PW8	---	---	---	---	---	2.96
Tank Truck Loading	---	---	---	---	---	49.08
Fugitives	---	---	---	---	---	7.06
Blowdowns	---	---	---	---	---	6.27
Total Emissions	**32.90**	**144.31**	**38.64**	**171.19**	**15.90**	**138.60**

[1] - Includes emissions from Startup, Shutdown, & Maintenance.

[2] - lb/hr & TPY emissions based on maximum values @ 0 ˚F.

Facility-Wide Criteria Pollutant Emissions for BCPP[1]

	SO_2		$PM_{10}/PM_{2.5}$		CO_{2e}[4]	
Sources	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-1	0.01	0.05	0.18	0.78	2,092	9,164
C-2	0.01	0.05	0.18	0.78	2,092	9,164
C-3	0.01	0.05	0.18	0.78	2,092	9,164
C-4	0.01	0.05	0.18	0.78	2,092	9,164
C-5	0.01	0.03	0.13	0.59	1,571	6,883
C-6	0.01	0.03	0.13	0.59	1,571	6,883
C-7	0.01	0.03	0.13	0.59	1,571	6,883
C-8	0.01	0.03	0.13	0.59	1,571	6,883
C-9	0.01	0.03	0.13	0.59	1,571	6,883
C-10	0.01	0.03	0.13	0.59	1,571	6,883
T-1[2, 3]	0.05	0.23	0.58	2.54	10,262	44,949
T-2[2, 3]	0.05	0.23	0.58	2.54	10,262	44,949
H-1	0.01	0.03	0.08	0.36	1,292	5,658
FLARE-1	6.07	26.57	0.08	0.34	5,267	23,071
FLARE-2	---	0.01	---	0.04	---	576
PW1-PW8	---	---	---	---	---	229
Tank Truck Loading	---	---	---	---	---	176
Fugitives	---	---	---	---	---	517
Blowdowns	---	---	---	---	---	528
Total Emissions	**6.28**	**27.45**	**2.82**	**12.48**	**44,877**	**198,607**

[1] - Includes emissions from Startup, Shutdown, & Maintenance.
[2] - lb/hr & TPY emissions based on maximum values @ 0 ˚F.
[3] - Based on converting LHV to HHV using a factor of 1.11.
[4] - Mainly CO_2 except for fugitives which are mostly CH_4.

Total Facility-Wide Criteria Pollutant Emissions

	NO_X		CO		VOC	
Sources	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
NEM	155.44	18.61	1,300.07	15.64	330.44	6.73
BCPP	32.90	144.31	38.64	171.19	15.90	138.60
Totals	**188.34**	**162.92**	**1,338.71**	**186.83**	**346.34**	**145.33**

Total Facility-Wide Criteria Pollutant Emissions

	SO_2		$PM_{10}/PM_{2.5}$		CO_{2e}[4]	
Sources	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
NEM	3,974.02	917.73	0.37	1.56	23,987	92,348
BCPP	6.28	27.45	2.82	12.48	44,877	198,607
Totals	**3,980.3**	**945.18**	**3.19**	**14.04**	**68,864**	**290,955**

SECTION VI. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified in the application are listed below. Records are available to confirm the insignificance of the activities. Record keeping for activities indicated with "*" is required in the Specific Conditions.

1. 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 lube oil and amine storage tanks on the site. The vapor pressures for lube oil and amine are less than 1.0 psia.

2. * Activities having the potential to emit no more than 5.0 TPY of any criteria pollutant. None identified but may be in the future.

SECTION VII. OKLAHOMA AIR QUALITY RULES

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

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration of Air Contaminant Sources) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories have been submitted and fees paid for 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 HAP or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are based on information in the application or developed from the applicable requirements.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for affirmative defense, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

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

OAC 252:100-19 (Control of Emission of 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. For fuel-burning equipment rated less than 1,000 MMBTUH but greater than 10 MMBTUH, the allowable PM emissions are calculated using the formula: $E = 1.042808\ X^{(-0.238561)}$, where E is the limit in lb/MMBTU and X is the maximum heat input. The table below lists the fuel-burning equipment greater than 10 MMBTUH and their applicable emission limits. For external combustion units burning natural gas, AP-42, Table 1.4-2 (7/98), lists the total PM emissions for natural gas to be 7.6 lb/MMft^3 or about 0.0076 lb/MMBTU. For 4-cycle lean-burn engines burning natural gas, AP-42 (7/00), Section 3.2, lists the total PM emissions as 0.00999 lb/MMBTU. For turbines burning natural gas, AP-42 (4/00), Section 3.1, lists the total PM emissions as 0.0066 lb/MMBTU.

NEM Equipment	Max. Heat Input (MMBTUH) (HHV)	Allowable PM Emission Rate (lb/MMBTU) (HHV)	Potential PM Emissions (lb/MMBTU) (HHV)
2,370-hp Caterpillar G3608LE	17.88	0.524	0.0100
1,775-hp Caterpillar G3606LE	13.43	0.561	0.0100
10,340-hp Solar Taurus 70-1080S	79.02	0.368	0.0066
Regeneration Heater	11.04	0.588	0.0076

The permit requires the use of natural gas for all fuel-burning equipment to ensure compliance with Subchapter 19

This subchapter also limits emissions of particulate matter from industrial processes and direct-fired fuel-burning equipment based on their process weight rates. Since there are no significant particulate emissions from the non-fuel-burning processes at the facility compliance with the standard is assured without any special monitoring provisions.

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. This permit requires the use of natural gas for all fuel-burning units to ensure compliance with Subchapter 25.

OAC 252:100-29 (Control of Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility 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]
<u>Part 2</u> limits the ambient air concentration of hydrogen sulfide (H_2S) emissions from any new or existing source to 0.2 ppmv (24-hour average) which is equivalent to 279 $\mu g/m^3$.

Air dispersion modeling was conducted for normal operation of the facility, for venting source gas to the flare during emergencies, and for operation under the AOS. US EPA's air dispersion model AERMOD (07026) was used for the modeling analyses. AERMOD is a refined, steady-state, multiple source, Gaussian dispersion model and is the preferred model for these analyses. The modeling analysis was performed using the regulatory default models settings, which include stack heights adjusted for stack-tip downwash and missing data processing. Source and building elevations were obtained from engineering elevation drawings. Receptor terrain elevations entered into the model were the highest elevations extracted from USGS 7.5 minute digital elevation model (DEM) data of the area surrounding the site. For each receptor elevation, the maximum terrain elevation associated with the four DEM points surrounding the receptor was selected.

As described in the *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits*, meteorological data was derived from Oklahoma Mesonet surface data, National Climactic Data Center (NCDC) Integrated Surface Hourly (ISH) data, and FSL/NCDC Radiosonde upper air data. Oklahoma Mesonet data was provided to the AQD courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University and The University of Oklahoma and supported by the taxpayers of Oklahoma. The model runs were performed using 2001-2005 meteorological data using NWS surface observations from Clinton-Sherman AFB, upper air measurements from Amarillo, Texas, and adjusting the surface data using the Oklahoma Mesonet data from Erik, OK. The 2001-05 data set used in this analysis was provided by the AQD.

A single Cartesian grid containing receptors spaced at 100 meter intervals extending from the facility fence line out to at least 1,800 m was used.

Ambient Impacts of H_2S

Averaging Time	**Standard**	**Operating Scenario & Max Impacts**	
	μg/m^3	**Normal, μg/m^3**	**AOS, μg/m^3**
24-hour	279	0.9	0.1

Part 5, Section 31-25 limits SO_2 emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb SO_2/MMBTU heat input averaged over 3 hours. For fuel gas having a gross calorific value of 1,000 BTU/SCF, this limit corresponds to fuel sulfur content of 1,203 ppmv. The permit requires the use of gaseous fuel with sulfur content less than 4 ppmv for the Buffalo Creek Processing Plant to ensure compliance with Subchapter 31.

Part 5, Section 31-26 (a)(1) & (c) requires H_2S from any new petroleum or natural gas process equipment (constructed after July 1, 1972) to be removed from the exhaust stream or to be oxidized to SO_2 unless H_2S emissions would be less than 0.3 lb/hr, two-hour average (OAC 252:100-31-26(b)(1)). H_2S emissions must be reduced by 95% of the H_2S in the exhaust gas. Per OAC 252:100-31-26(b)(2), direct oxidation of H_2S is allowed for units whose SO_2 emissions would be less than 100 lb/hr, two-hour average. Otherwise, the facility must comply with the sulfur reduction efficiencies of OAC 252:100-31-26(a)(2). All new thermal devices for petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(a)(1) shall have installed, calibrated, maintained, and operated an alarm system that will signal noncombustion of the gas.

Emissions from the flash tank and still vent of the amine unit are vented to the acid gas flare with a combustion efficiency of 98%. At 4 ppmv, 220 MMSCFD, and 100% collection, the maximum amount of SO_2 that could be emitted from the amine unit would be 6.2 lb/hr. The flare will be equipped with an alarm system that will signal when there is no pilot flame. The permit will require compliance with all applicable requirements.

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 NO_X per MMBTU, three-hour average. The turbines and the hot oil heater exceed the 50 MMBTUH threshold.

Emissions of NO_X from the turbines are approximately 0.061 lb/MMTBU which is in compliance with this subchapter. Compliance with the BACT emission limits will ensure compliance with this subchapter.

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

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The stabilized condensate tanks are subject to this subchapter and are equipped with an organic vapor recovery system.
Part 3 requires VOC loading facilities with a throughput greater than 40,000 gallons per day to be equipped with a vapor-collection and disposal system. When loading all loading and vapor lines shall be equipped with fittings that make vapor-tight connections and which must be closed when disconnected or which close automatically when disconnected. The vapor-disposal portion of the system shall consist of a vapor-liquid absorber system with a minimum recovery efficiency of 90 percent by weight of all the VOC vapors and gases entering such disposal system; or a variable-vapor space tank, compressor, and fuel-gas system of sufficient capacity to receive all VOC vapors and gases displaced from the tank trucks and trailers being loaded. A means shall be provided to prevent VOC drainage from the loading device when it is removed from any tank truck or trailer, or to accomplish complete drainage before removal. The estimated throughput of the loading rack at the facility is greater than 40,000 gallons per day. All applicable requirements have been incorporated into the permit.
Part 5 limits the VOC content of coatings from any coating line or other coating operation. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize VOC emissions. Temperature and available air must be sufficient to provide essentially complete combustion.
Part 7 requires all effluent water separators openings or floating roofs to be sealed or equipped with an organic vapor recovery system. There are no effluent water separators located at this facility.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may

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

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

OAC 252:100-11	Alternative Emissions Reduction	not eligible
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain, Feed, or Seed Facility	not in source category
OAC 252:100-39	Non-attainment Areas	not in a subject area
OAC 252:100-47	Municipal Solid Waste Landfills	not type of source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
Total potential emissions of SO_2 are greater than the major source threshold of 250 TPY. This modification resulted in a significant emission increase and a significant net emission increase for NO_X, CO, VOC, $PM_{2.5}$, and CO_{2e}. The PSD review is in Section IV. Any future increases of emissions must be evaluated for PSD if they exceed a significance level (40 TPY NO_X, 100 TPY CO, 40 TPY VOC, 40 TPY SO_2, 25 TPY PM_{10}, and 75K TPY CO_{2e}).

NSPS, 40 CFR Part 60 [Subparts JJJJ, KKKK, and OOOO Are Applicable]
Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam-generating units constructed after June 9, 1989, and with capacity between 10 and 100 MMBTUH. The amine unit regenerator is not considered a “Steam Generating Unit” as that term is defined in this subpart and is not subject to this subpart.

Subpart GG, Stationary Gas Turbines. This subpart affects stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBTUH, based on the LHV of the fuel fired which commence construction, modification, or reconstruction after October 3, 1977, but on or before February 18, 2005. The turbines located at this facility were constructed after February 18, 2005, and are subject to NSPS, Subpart KKKK.

Subpart Kb, VOL Storage Vessels. This subpart regulates hydrocarbon storage tanks larger than 19,813-gal capacity and built after July 23, 1984. There are no tanks storing materials with a vapor pressure greater than 1.5 psia and all tanks have capacities less than the threshold.

Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011. This subpart sets standards for natural gas processing plants which are defined as any site engaged in the extraction of natural gas liquids from field gas, fractionation of natural gas liquids, or both. 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 site.

This NEM facility does not engage in natural gas processing. However, since it will be located at a gas plant it is subject to this subpart and the permit will require the facility to modify it's current operating permit after construction of the gas plant.

The BCPP facility will commenced construction after August 23, 2011, and is subject to NSPS, Subpart OOOO.

Subpart LLL, Onshore Natural Gas Processing: SO_2 Emissions for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011. The amine unit at the BCPP facility processes sweet natural gas (≤ 0.25 grains/DSCF; ≤ 4 ppmv) and is not subject to this subpart.

Subpart IIII, Stationary Compression Ignition (CI) Internal Combustion Engines (ICE). This subpart affects CI ICE, that are not fire pump engines, which commenced construction after July 1, 2005, and were manufactured after April 1, 2006. No CI ICE were proposed for this facility.

Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart promulgates emission standards for all new SI engines ordered after June 12, 2006 and all SI engines modified or reconstructed after June 12, 2006, regardless of size. Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 100-hp under the voluntary manufacturer certification program must certify those engines to the emission standards in Table 1 to this subpart. Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100-hp must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE.

Emission Standards from Table 1, Subpart JJJJ, g/hp-hr (ppmvd @ 15%O_2)

Engine Type & Fuel	Max Power (hp)	Mfg. Date	NO_X	CO	VOC
Non-Emergency SI Natural Gas[1]	hp ≥ 500	7/1/2007	2.0 (160)	4.0 (540)	1.0 (86)
		7/1/2010	1.0 (80)	2.0 (270)	0.7 (60)

[1] - except lean burn 500 ≤ HP < 1,350

An initial notification is required only for owners and operators of engines greater than 500 HP that are non-certified. Owners or operators must demonstrate compliance with the applicable emissions limits according to one of the following methods:

- Purchase a certified engine and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions
- Purchasing a certified engine (that is not operated and maintained according to the manufacturer's emission-related written instructions) or a non-certified engine and maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions and for engines greater than 500-hp conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years.

The new 2,370-hp Caterpillar G3608LE engines and 1,775-hp Caterpillar G3606LE engine were constructed after June 12, 2006, and are subject to this subpart. The engines may not be certified and/or maintained according to manufacturer’s emission-related written instructions and will be subject to initial and periodic testing under this subpart. All applicable requirements have been incorporated into the permit.

Subpart KKKK, Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBTU) per hour, based on the higher heating value of the fuel, that commenced construction, modification, or reconstruction after February 18, 2005. Stationary combustion turbines regulated under this subpart are exempt from the requirements of Subpart GG. New natural gas fired turbines with a heat input at peak load of > 50 MMBTUH and ≤ 850 MMBTUH must meet a NO_X emission limit of ≤ 25 ppmdv @ 15% O_2. Turbines are also subject to either the SO_2 emission limitation of § 60.4330(a)(1) (0.90 lb SO_2/MWhr) or the fuel sulfur content limitation of § 60.4330(a)(2) (0.060 lb SO_2/MMBTU). Owners or operators must operate and maintain each turbine in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. Owners or operators must demonstrate compliance with the applicable NO_X emission limit by performing annual testing or through use of either continuous emission monitoring or continuous parameter monitoring. If the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specify that the total sulfur content for natural gas is ≤ 20 gr/100 SCF the owner or operator is exempt from monitoring the total sulfur content of the fuel.

The new stationary combustion turbines were constructed after the applicability date of this subpart and are subject to this subpart. The facility will use continuous parameter monitoring or continuous emission monitoring to demonstrate compliance with the NO_X standard. The facility will comply with the SO_2 standard by demonstrating that the fuel sulfur content does not exceed 20 gr/100 SCF. The permit will incorporate all applicable requirements.

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart was promulgated on August 16, 2012, and affects the following sources that commence construction, reconstruction, or modification after August 23, 2011:

1. Each single gas well;
2. Single centrifugal compressors using wet seals that are located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment;
3. Reciprocating compressors which are single reciprocating compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment;
4. Single continuous bleed natural gas driven pneumatic controllers, with a natural gas bleed rate greater than 6 SCFH, located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment and not located at a natural gas processing plant;
5. Single continuous bleed natural gas driven pneumatic controllers located at a natural gas processing plant;
6. Single storage vessels located in the oil and natural gas production segment, natural gas processing segment, or natural gas transmission and storage segment;
7. All equipment, except compressors, within a process unit at an onshore natural gas processing plant;
8. Sweetening units located at onshore natural gas processing plants.

For each centrifugal compressor using wet seals, the owner/operator must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater. The new centrifugal compressors are subject to this subpart.

For each reciprocating compressor the owner/operator must replace the rod packing before 26,000 hours of operation or prior to 36 months. If utilizing the number of hours, the hours of operation must be continuously monitored. The new compressors will be subject to this subpart.

Pneumatic controllers at a natural gas processing plant must have a bleed rate of zero. All new pneumatic controllers at this facility will have to comply with this subpart.

Storage vessels constructed, modified or reconstructed after August 23, 2011, with VOC emissions equal to or greater than 6 TPY must reduce VOC emissions by 95.0 % or greater. All new or modified storage vessels will have to comply with this subpart.

The group of all equipment, except compressors, within a process unit at a natural gas processing plant, must comply with the requirements of NSPS, Subpart VVa, except as provided in §60.5401. All new or modified process units will have to comply with this subpart.

A sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream. A sour natural gas stream is defined as containing greater than or equal to 0.25 grains sulfur per 100 standard cubic feet or 4 ppmv. The existing amine unit commenced construction prior to August 23, 2011, and has not been modified or reconstructed. The new amine unit will process sweet natural gas and is not subject to this subpart.

The permit will require the facility to comply with all applicable requirements of NSPS, Subpart OOOO.

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. All process streams at this facility are below this threshold.

NESHAP, 40 CFR 63 [Subpart ZZZZ is Applicable]
Subpart HH, Oil and Natural Gas Production Facilities. This subpart applies to affected emission points that are located at facilities that are major and area sources of HAP, and either process, upgrade, or store hydrocarbon liquids prior to custody transfer or that process, upgrade, or store natural gas prior to entering 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 present. The only affected source at area sources are triethylene glycol (TEG) dehydration units. The combined HAP emissions from this facility are less than the major source thresholds. There are no TEG dehydration units at the BCPP facility.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines):

1) Stationary RICE located at an area source;
2) The following Stationary RICE located at a major source of HAP emissions:
   i) 2SLB and 4SRB stationary RICE with a site rating of ≤ 500 brake HP;
   ii) 4SLB stationary RICE with a site rating of < 250 brake HP;
   iii) Stationary RICE with a site rating of ≤ 500 brake HP which combust landfill or digester gas equivalent to 10% or more of the gross heat input on an annual basis;
   iv) Emergency or limited use stationary RICE with a site rating of ≤ 500 brake HP; and
   v) CI stationary RICE with a site rating of ≤ 500 brake HP.

No further requirements apply for engines subject to NSPS under this part. A stationary RICE located at an area source of HAP emissions is new if construction commenced on or after June 12, 2006. The new engines are subject to this subpart and will comply with this subpart by complying with NSPS, Subpart JJJJ. All applicable requirements have been incorporated into the permit.

Subpart JJJJJJ, Industrial, Commercial, and Institutional Boilers. This subpart affects new and existing boilers located at area sources of HAP, except for gas-fired boilers. Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam or hot water. Gas fired boilers are defined as any boiler that burns gaseous fuel not combined with any solid fuels, liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. The regeneration heater is not considered a boiler and is not subject to this subpart.

Compliance Assurance Monitoring (CAM), 40 CFR Part 64 [Not Applicable]
This part applies to any pollutant-specific emission unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 18, 1998, that addresses "large emissions units," or any application that addresses "large emissions units" as a significant modification to an operating permit, or for any application for renewal of an operating 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; and
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source thresholds (100 TPY of a criteria pollutant, 10 TPY of a HAP, or 25 TPY of total HAP).

The engines utilize oxidation catalyst to comply with the applicable CO emission limits. However, the potential to emit CO for each engine is less than major source levels. Therefore, the engines are not subject to CAM.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
This facility will handle naturally occurring hydrocarbon mixtures at a natural gas processing plant and the Accidental Release Prevention Provisions are applicable to this facility. The facility is required to submit the appropriate accidental release emergency response program plan prior to operation of the facility. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Not Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

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

SECTION IX. COMPLIANCE

Tier Classification

This application has been determined to be Tier II based on the request for a construction permit to make a physical change that will result in a significant modification of a Part 70 source operating permit. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

Public Review

The applicant published the “Notice of Filing a Tier II Application” in *The Sayre Record* a weekly newspaper in Beckham County on July 25, 2012. The notice stated that the application was available for public review for a period of 30 days at the Sayre Public Library located at 113 E. Poplar Street, Sayre, Oklahoma and that the application was also available for public review at the Air Quality Division main office. The applicant also published the “Notice of Draft Permit” in *The Sayre Record* a weekly newspaper in Beckham County on July 25, 2012. The notice stated that the draft permit was available for public review for a period of 30 days at the Sayre Public Library located at 113 E. Poplar Street, Sayre, Oklahoma and that the draft permit was also available for public review at the Air Quality Division main office and on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*. No comments were received from the public.

State Review
This facility is located within 50 miles of the Oklahoma - Texas Border. The state of Texas was notified of the draft permit. No comments were received from the state of Texas.

EPA Review
This permit was approved for concurrent public and EPA review. The draft was forwarded to EPA for a 45-day review period. Since there were no public comments the draft permit was deemed the proposed permit. Comments were received from the EPA and were addressed. However, since they did not result in a change to the specific conditions of the permit, they are not addressed here.

Fees Paid
Part 70 source construction permit application fee of $1,500 for modification of an existing Part 70 source.

SECTION X. SUMMARY

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

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Mid-America Midstream Gas Services, L.L.C.
Buffalo Creek Processing Plant (BCPP) (SIC 1321)

Permit Number 2012-1026-C PSD

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on February 21, 2012, and all supplemental materials. The Evaluation Memorandum dated September 6, 2012, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction/continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

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

BCPP-EUG A. Reciprocating Internal Combustion Engines: Emission limitations have been established for EU C-1 through C-10 and include startup, shutdown, and maintenance (SSM). All other emissions were based on the heat input rating, AP-42 (7/98), Section 1.4, and a fuel sulfur content of 4 ppmv (0.000675 lb/MMBTU). Emission limitations for emission units (EU) C-1 through C-10:

			NO_X		CO		VOC	
EU	**Point**	**Engine Make/Model**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-1	C-1	2,370-hp Caterpillar G3608LE w/Oxidation Catalyst	2.61	11.44	2.87	12.59	1.15	5.03
C-2	C-2	2,370-hp Caterpillar G3608LE w/Oxidation Catalyst	2.61	11.44	2.87	12.59	1.15	5.03
C-3	C-3	2,370-hp Caterpillar G3608LE w/Oxidation Catalyst	2.61	11.44	2.87	12.59	1.15	5.03
C-4	C-4	2,370-hp Caterpillar G3608LE w/Oxidation Catalyst	2.61	11.44	2.87	12.59	1.15	5.03
C-5	C-5	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	2.15	9.43	0.86	3.77
C-6	C-6	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	2.15	9.43	0.86	3.77
C-7	C-7	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	2.15	9.43	0.86	3.77
C-8	C-8	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	2.15	9.43	0.86	3.77
C-9	C-9	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	2.15	9.43	0.86	3.77
C-10	C-10	1,775-hp Caterpillar G3606LE w/Oxidation Catalyst	1.96	8.57	2.15	9.43	0.86	3.77

Name/Model	NO_X (g/hp-hr)[2]	CO (g/hp-hr)[2]	VOC (g/hp-hr)[2]	$PM_{2.5}$ (lb/MMBTU)[2, 3]	CO_{2e} (BTU/bhp-hr)[2, 4, 5]
2,370-hp Cat. G3608LE[1]	0.50	0.55	0.22	0.066	≤ 7,900
1,775-hp Cat. G3606LE[1]	0.50	0.55	0.22	0.066	≤ 7,900

[1] - with oxidation catalyst
[2] - Based on a three hour average.
[3] - Based on AP-42 (4/2000), Section 3.2.
[4] - Based on loads ≥ 75%.
[5] - Based on HHV

a. The engines shall only be fired with natural gas having a maximum sulfur content of 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once every calendar year.
[OAC 252:100-31]

b. Each lean-burn engine shall be equipped with a properly functioning oxidation catalyst.
[OAC 252:100-8-6(a)(1)]

c. Each engine shall have a permanent identification plate attached that shows the make, model number, and serial number. [OAC 252:100-43]

d. At least once per calendar quarter, the permittee shall conduct tests of NO_X and CO emissions from the engine(s) and from each replacement engine/turbine when operating under representative conditions for that period. Testing is required for any engine/turbine that runs for more than 220 hours during that calendar quarter. A quarterly test may be conducted no sooner than 20 calendar days after the most recent 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 the 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. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test. 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. Reduced testing frequency does not apply to engines with catalytic converters or oxidation catalyst. [OAC 252:100-8-6 (a)(3)(A)]

e. When periodic compliance testing shows engine exhaust emissions in excess of the lb/hr limits, the permittee shall comply with the provisions of OAC 252:100-9.
[OAC 252:100-9]

f. The owner/operator (O/O) shall comply with the Standards of Performance for Stationary Spark Ignition Internal Combustion Engine (SI-ICE), NSPS Subpart JJJJ, for all affected emission units, including but not limited to the following: [40 CFR §§ 60.4230-60.4248]

Emission Standards for O/O

i. § 60.4233 What emission standards must I meet if I am an O/O of a stationary SI-ICE?

ii. § 60.4234 How long must I meet the emission standards if I am an O/O of a stationary SI-ICE?

Other Requirements for O/O

iii. § 60.4236 What is the deadline for importing or installing stationary SI ICE produced in the previous model year?

iv. § 60.4237 What are the monitoring requirements if I am an O/O of an emergency stationary SI-ICE?

Compliance Requirements for O/O

v. § 60.4243 What are my compliance requirements if I am an O/O of a stationary SI-ICE?

Testing Requirements for O/O

vi. § 60.4244 What test methods and other procedures must I use if I am an O/O of a stationary SI-ICE?

Notification, Reports, and Records for O/O

vii. § 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an O/O of a stationary SI-ICE?

General Provisions

viii. § 60.4246 What parts of the General Provisions apply to me?

BCPP-EUG B. Combustion Turbines: Emission limitations have been established for EU T-1 and T-2 and include SSM. All other emissions were based on the heat input rating, AP-42 (4/2000), Section 3.1, and a fuel sulfur content of 4 ppmv (0.000675 lb/MMBTU).

EU	Point	Make/Model	hp
T-1	T-1	Solar Taurus 70-10802S	10,179
T-2	T-2	Solar Taurus 70-10802S	10,179

Emissions limits for each turbine (EU T-1 and T-2):

Pollutant	lb/hr	ppmvd[1]	TPY
NO_X	4.75[2]	15.0[2]	20.77
CO	4.82[3]	25.0[3]	21.11
VOC	2.76[3]	25.0[3]	12.11

1 All concentrations are corrected to 15% O_2, per turbine.
2 One-hour average.
3 Three-hour average.

Pollutant	lb/MMBTU[1, 2]
$PM_{2.5}$	0.0066

[1] - Based on AP-42 (4/2000), Section 3.1.
[2] Three-hour average.

Pollutant	BTU/bhp-hr[1, 2, 3]
CO_{2e}	≤ 8,220

[1] - Based on loads ≥ 75%.
[2] - Based on LHV
[3] - Three-hour average.

a. The turbines shall only be fired with natural gas having a maximum sulfur content of 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once every calendar year. [OAC 252:100-31]

b. Each turbine shall have a permanent identification plate attached that shows the make, model number, and serial number. [OAC 252:100-43]

c. The turbines shall be equipped with Solar's SoLoNO$_X$™ technology (Lean-Premixed, Dry, Low-NO$_X$ Combustors). [OAC 252:100-8-6(a)(1)]

d. Each turbine shall be equipped and operated with NO_X CEM or CPM that complies with the requirements of NSPS, Subpart KKKK. [OAC 252:100-8-6(a)(3)]

e. When monitoring shows turbine exhaust emissions in excess of the limits, the permittee shall comply with the provisions of OAC 252:100-9. [OAC 252:100-9]

f. The turbines are subject to the NSPS for Stationary Combustion Turbines 40 CFR Part 60, Subpart KKKK and shall comply with all applicable requirements including but not limited to: [40 CFR § 60.4300 to § 60.4420]

<u>Introduction</u>

i. §60.4300 What is the purpose of this subpart?

ii. Applicability

iii. § 60.4305 Does this subpart apply to my stationary combustion turbine?

iv. § 60.4310 What types of operations are exempt from these standards of performance?

<u>Emission Limits</u>

v. § 60.4315 What pollutants are regulated by this subpart?

vi. § 60.4320 What emission limits must I meet for nitrogen oxides (NO_X)?

vii. § 60.4325 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

viii. § 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

<u>General Compliance Requirements</u>

ix. §60.4333 What are my general requirements for complying with this subpart?

<u>Monitoring</u>

x. § 60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

xi. § 60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?
xii. § 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
xiii. § 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?
xiv. § 60.4355 How do I establish and document a proper parameter monitoring plan?
xv. § 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?
xvi. § 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?
xvii. § 60.4370 How often must I determine the sulfur content of the fuel?

<u>Reporting</u>

xviii. § 60.4375 What reports must I submit?
xix. § 60.4380 How are excess emissions and monitor downtime defined for NO_X?
xx. § 60.4385 How are excess emissions and monitoring downtime defined for SO_2?
xxi. § 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
xxii. § 60.4395 When must I submit my reports?

<u>Performance Tests</u>

xxiii. § 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?
xxiv. § 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
xxv. § 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

<u>Definitions</u>

xxvi. § 60.4420 What definitions apply to this subpart?

BCPP-EUG C. Gas-Fired Heater: Emission limits have been established for NO_X and CO for EU H-1. All other emissions were based on the heat input rating, AP-42 (7/98), Section 1.4, and a fuel sulfur content of 4 ppmv (0.000675 lb/MMBTU).

EU	**Point**	**Description**	**MMBTUH**
H-1	H-1	Regeneration Heater	11.04

Emissions limits for EU H-1:

Pollutant	**lb/hr**	**lb/MMBTU**	**ppmvd[1]**	**TPY**
NO_X	0.50[2]	0.045	36[2]	2.18
CO	0.82[2]	0.074	93[2]	3.58

[1] All concentrations are corrected to 3% O_2.
[2] Three-hour average.

a. The heater shall only be fired with natural gas having a maximum sulfur content of 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once every calendar year.

b. The heater shall be equipped with Low-NO_X burners. [OAC 252:100-8-6(a)(1)]

BCPP-EUG D. Amine Unit: No emission limits have been established for EU AMINE-1 since the emissions from this unit are routed to the Acid Gas Flare (EU FLARE-1). However, a throughput limit and sulfur content limit on the gas processed has been established.

EU	Point	Name	Throughput
AMINE-1	AMINE-1	Amine Unit	230 MMSCFD

a. The amine unit shall only process natural gas with a maximum sulfur content of 0.25 grains or less of total sulfur (as hydrogen sulfide) per 100 standard cubic feet (< 4 ppmv). Compliance can be shown by the following methods: a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least monthly. [OAC 252:100-31]

b. The throughput of the amine unit shall be limited to 230 MMSCFD. The permittee shall keep records of the amount of gas processed through the amine unit on a daily basis.

c. The amine unit still vent and flash tank shall be routed to the Acid Gas Flare.

BCPP-EUG E. Flares: Emission limits have been established for SO_2 for EU FALRE-1. All other emissions were based on the heat input rating, AP-42 (1/95), Section 13.5, an estimated amount of waste gas and heat content. Emissions from EU FLARE-2 are insignificant.

EU	Point	Emission Unit
FLARE-1	FLARE-1	Acid Gas Flare
FLARE-2	FLARE-2	Main Plant Flare

	SO_2	
Sources	lb/hr	TPY
FLARE-1	6.07	26.57

a. The amine unit's still vent and flash tank shall be routed to the Acid Gas Flare (EU FLARE-1) an oxidation system that will remove or oxidize the H_2S to SO_2 with an efficiency of at least 95%. [OAC 252:100-31-26(a)(1)]

b. The Acid Gas Flare (EU FLARE-1) shall have installed, calibrated, maintained, and operated an alarm system that will signal non-combustion of the gas.

[OAC 252:100-31-26(c)]

BCPP-EUG F. Condensate Tanks: No emissions were estimated from the gas plant condensate production since the gas plant will be equipped with a condensate stabilizer that is vented to the gas plant or compressor station inlet.

EU	Point	Contents	Barrels	Gallons
TK-1	TK-1	Condensate	400	16,800
TK-2	TK-2	Condensate	400	16,800
TK-3	TK-3	Condensate	400	16,800
TK-4	TK-4	Condensate	400	16,800
TK-5	TK-5	Condensate	400	16,800
TK-6	TK-6	Condensate	400	16,800
TK-8	TK-8	Condensate	400	16,800

a. The produced liquids from the inlet separator shall be treated by a condensate stabilizer. The off-gases from the stabilizer shall be recycled/recompressed into the inlet manifold of the gas plant.
b. The condensate tanks shall be routed to a vapor collection system. The off-gases from the condensate tanks shall be routed to the Main Plant Flare (EU FLARE-2) or recycled to the inlet manifold of the gas plant. All vessel gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

BCPP-EUG G. Produced Water Tanks: Emission estimates from the Produced Water Tanks were estimated based on an average factor of 10 SCF of vapor per barrel of produced water and 200 barrels per day (BPD) of produced water. Emissions from the Produced Water Tanks are considered insignificant.

EU	Point	Contents	Barrels	Gallons
PW-1	PW-1	Produced Water	200	8,400
PW-2	PW-2	Produced Water	200	8,400
PW-3	PW-3	Produced Water	200	8,400
PW-4	PW-4	Produced Water	200	8,400
PW-5	PW-5	Produced Water	200	8,400
PW-6	PW-6	Produced Water	200	8,400

a. The throughput of the EUG G shall be limited to 200 BPD (monthly average). The permittee shall keep records of the amount of liquids processed through EUG G on a monthly basis.

BCPP-EUG H. Truck Loading: Emission estimates from loading condensate into tank trucks were estimated based on AP-42 (1/95), Section 5.2, a throughput of 1,460,000 barrels per year (BPY), a 70% collection efficiency for vapor balancing, and a 98% destruction efficiency because the tanks are vented to the main plant flare.

EU	Point	Name	Throughput
L-1	L-1	Condensate Truck Loading	1,460 MBPY

	VOC
Sources	**TPY**
Tank Truck Loading	49.08

a. Condensate throughput shall not exceed 1,460,000 barrels in any 12-month period. The permittee shall monitor and record the condensate throughput each month.

b. The condensate loading system shall be equipped with a vapor recovery system that collects the gases from the tank trucks being loaded and routes the vapors back to the tanks being unloaded.

   i. All loading and vapor lines for the stabilized condensate loading system shall be equipped with fittings that make vapor-tight connections and which close automatically when disconnected.

   ii. A means shall be provided to prevent VOC drainage from the stabilized condensate loading device when it is removed from the tank truck or which completely drains before removal.

   iii. The tank truck shall also be equipped with a vapor collection system that will route the displaced VOC vapors from the tank truck being loaded to the stabilized condensate loading vapor recovery system.

   iv. The tank truck vapor system shall be connected to the stabilized condensate vapor recovery system when loading stabilized condensate from the gas plant.

BCPP-EUG I. Fugitives: Emissions from the fugitive equipment leaks are based on equipment type, the number of components and the average emission factors for oil and gas facilities. There are no emission limits applied to these EU but they are required to meet certain work practices.

EU	Point	Number Items	Type of Equipment
FUG	FUG	762	Valves
		2,661	Flanges
		13	Open-ended Lines
		5	Pump Seals
		39	Other

BCPP-EUG J. Blowdowns: Emissions from the blowdowns are based on an estimated throughput of 1.44 MMSCFY.

EU	Point	Name	Throughput
BD	BD	Blowdowns	1.44 MMSCFY

a. Blowdowns shall not exceed 1.44 MMSCF in any 12-month period. The permittee shall monitor and record the amount of gases related to blowdowns each month.

2. 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)]

3. Replacement (including temporary periods of 6 months or less for maintenance purposes), of internal combustion engine(s)/turbine(s) with emissions limitations specified in this permit with engine(s)/turbine(s) of lesser or equal emissions of each pollutant (in lbs/hr and TPY) are authorized under the following conditions. [OAC 252:100-8-6(f)(2)]

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, serial number, horsepower rating, 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), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location.

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

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

e. Turbines installed as allowed under the replacement allowances in this Specific Condition that are subject to 40 CFR Part 60, Subpart KKKK shall comply with all applicable requirements.

4. The owner/operator shall comply with all applicable requirements of 40 CFR Part 63, NESHAP, Subpart ZZZZ: Reciprocating Internal Combustion Engines, for each affected facility including but not limited to: [40 CFR 63.6580 through 63.6675]

<u>What This Subpart Covers</u>

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

<u>Other Requirements and Information</u>

e. § 63.6665 What parts of the General Provisions apply to me?
f. § 63.6670 Who implements and enforces this subpart?
g. § 63.6675 What definitions apply to this subpart?

5. The permittee shall comply with NSPS, Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transportation, and Distribution, for all affected facility located at this facility. [40 CFR 60.5360 to 60.5430]

a. § 60.5360 What is the purpose of this subpart?
b. § 60.5365 Am I subject to this subpart?
c. § 60.5370 When must I comply with this subpart?
d. § 60.5375 What standards apply to gas well affected facilities?
e. § 60.5380 What standards apply to centrifugal compressor affected facilities?
f. § 60.5385 What standards apply to reciprocating compressor affected facilities?
g. § 60.5390 What standards apply to pneumatic controller affected facilities?
h. § 60.5395 What standards apply to storage vessel affected facilities?
i. § 60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?
j. § 60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?
k. § 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?
l. § 60.5405 What standards apply to sweetening units at onshore natural gas processing plants?
m. § 60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?
n. § 60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?
o. § 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas-Tutwiler Procedure?

p. § 60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
q. § 60.5411 What additional requirements must I meet to determine initial compliance for my closed vent systems routing emissions from storage vessels or centrifugal compressor wet seal fluid degassing systems?
r. § 60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?
s. § 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?
t. § 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
u. § 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel or centrifugal compressor affected facility?
v. § 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?
w. § 60.5420 What are my notification, reporting, and recordkeeping requirements?
x. § 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
y. § 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
z. § 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
aa. § 60.5425 What parts of the General Provisions apply to me?
bb. § 60.5430 What definitions apply to this subpart?

6. 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 activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions from that activity (annual).

7. 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. Periodic emission testing for the engines and each replacement engine/turbine.
b. Operating hours for the engines if less than 220 hours per quarter and not tested.
c. O&M records for an engine if not tested in each 6-month period.
d. Records of the flare pilot flame outages.
e. Records required by NSPS, Subparts A, Dc, IIII, JJJJ, and OOOO.
f. Records required by NESHAP, Subpart ZZZZ.
g. Flow rate of the acid gas from the amine unit (quarterly average).
h. Amine unit emission estimates and H_2S concentrations of the natural gas or natural gas liquids (quarterly).
i. Condensate throughput for the gas plant (monthly and 12-month rolling totals).
j. Records required by Specific Condition No. 2.

8. No later than 30 days after each anniversary date of the issuance of the original Part 70 permit (February 10, 2000), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit. [OAC 252:100-8-6 (c)(5)(A) & (D)]

9. Within 180 days of commencement of operation of the BCPP facility, the owner/operator shall submit an administratively complete operating permit application. The permittee shall also include in the application testing for the engines/turbines showing compliance with the applicable emission limitations in accordance with NSPS, Subparts JJJJ and KKKK. The permittee shall also determine the NO_2/NO_X in stack ratio for the engines and the turbines during the applicable NSPS testing.

10. In addition to the testing required by NSPS, Subpart KKKK, the permittee shall conduct initial compliance testing for emissions of CO, $PM_{2.5}$, VOC, and formaldehyde on the new turbines (T-1 and T-2) at the 60% and 100% operating rates. Performance testing shall be conducted while the new units are operating within 10% of the desired operating rates. A written testing protocol shall be submitted to the AQD for review and approval at least 30 days prior to the start of such testing. The protocol shall describe how the testing will be performed.

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

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
Method 4:	Determination of Moisture in Stack Gases.
Method 5:	Determination of Particulate Emissions from stationary sources.

Method 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
Method 25/25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.
Method 201A:	Determination of $PM_{2.5}$ Emissions
Method 202:	Condensable Particulate Matter
Method 320:	Vapor Phase Organic & Inorganic Emissions by Extractive FTIR

11. Within 180 days of commencement of operation of the BCPP facility, the owner/operator for the Bluestem Gas Services, L.L.C., N.E. Mayfield Gas Plant shall submit an application to modify it's current operating permit to incorporate any new applicable requirements that will result from construction of the BCPP facility.

12. All modifications of this facility shall take into account the emissions from the Bluestem Gas Services, L.L.C., N.E. Mayfield Gas Plant.

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(July 21, 2009)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:

(1)the date, place and time of sampling or measurement;
(2)the date or dates analyses were performed;
(3)the company or entity which performed the analyses;
(4)the analytical techniques or methods used;
(5)the results of such analyses; and
(6)the operating conditions existing at the time of sampling or measurement.

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

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

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

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]
   (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
   (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
   (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
   (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and

the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;

(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and

(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;

(2) Equipment used during the maintenance, service, repair, or disposal of appliances must

comply with the standards for recycling and recovery equipment pursuant to § 82.158;

(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;

(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;

(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and

(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.

(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).

(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 C.F.R. § 70.8(d).

(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ

as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

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. 2012-1026-C PSD

Mid-America Midstream Gas Services, L.L.C.,

having complied with the requirements of the law, is hereby granted permission to construct/operate the Buffalo Creek Processing Plant, NE/4 of Section 3, T10N, R25W, Beckham County, Oklahoma, subject to Specific Conditions and Standard Conditions dated July 21, 2009, both of which are attached:

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

Division Director **Date**

Air Quality Division

DEQ Form #100-890

Kristin Ikard
Corp. Air Coordinator
Chesapeake Energy Corporation
6100 N. Western Ave.
Oklahoma City, OK 73118

SUBJECT:	Permit Number:	**2012-1026-C PSD**
	Facility:	Buffalo Creek Processing Plant
	Company:	Mid-America Midstream Gas Services, L.L.C.
	Location:	NE/4, Section 3, T10N, R25W, Beckham County, Oklahoma

Dear Ms. Ikard:

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

If you have any questions, refer to the permit number above and contact Eric Milligan at eric.milligan@deq.ok.gov or at (405) 702-4217. Thank you for your cooperation.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
AIR QUALITY DIVISION

Enclosures