OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **September 18, 2006**

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

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

THROUGH: Peer Review

FROM: Grover R. Campbell, P.E., Existing Source Permit Section

SUBJECT: Evaluation of Permit Application **No. 2002-476-C (M-2) PSD**
ConocoPhillips, Ponca City Refinery
No. 1 Crude Topping Unit Upgrade
Ponca City, Kay County, Oklahoma
Latitude 36.700°N, Longitude 97.087°W

SECTION I. INTRODUCTION

A. Original Permit

ConocoPhillips owns and operates the Ponca City Refinery (Refinery) which is located just south of Ponca City, Oklahoma, and is divided into five main areas based on the layout of the operations: East Plant, West Plant, South Plant, Coker/Combo/Alky, and Oil Movements. Each area consists of major processing units and other supplementary units that aid in the refining operations.

The refinery is a Title V major source and is located in an area designated as attainment for all criteria air pollutants. The refinery submitted an initial Part 70 Permit application (Permit Application Number 98-104-TV) on March 17, 1998. The primary Standard Industrial Classification (SIC) code for the refinery is 2911 (Petroleum Refining). The refinery is an existing major source for the federal Prevention of Significant Deterioration (PSD) program and a Maximum Achievable Control Technology (MACT) source category regulated by 40 CFR Part 63, Subpart CC and Subpart UUU. The facility is also subject to the emissions reduction agreements of Consent Decree No. H-01-4430 (Consent Decree).

On March 31, 2004, ConocoPhillips requested a construction permit to modify various equipment including: the No. 1 Crude Topping Unit (No. 1 CTU), the No. 7 Coker Unit, the No. 2 Catalytic Reforming Unit (No. 2 CRU), and the No. 7 Hydrotreater Unit (No. 7 HDT). The changes provided for increased production/efficiency at the refinery. Permit No. 2002-476-C (PSD) was issued to ConocoPhillips on March 31, 2004.

B. Modification (M-1)

ConocoPhillips requested a modification of Permit No. 2002-476-C (PSD) on March 14, 2005. Among other things, Permit No. 2002-476-C (PSD) required installation of Ultra Low NO_X Burners (ULNB) in Heater H-0001, the No. 1 Crude Topping Unit Charge Heater, and in Heater H-0048, the No. 2 Catalytic Reformer Unit Reactor Preheater. ULNB were installed in H-0001 and H-0048 during unit shutdowns in the 4^{th} quarter of 2004. However, after startup of the units, it was discovered that the new burners could not meet the permitted NO_X emission limits despite engineering and operation efforts to do so. Although the burners tested below 0.04 lb/MMBtu during test stand operations, retrofitting the existing fireboxes of the heaters with the new burners did not yield the same results. According to ConocoPhillips and based on information from other refinery experiences, this is not an unusual situation as actual performance of new generation low-NO_X burners as retrofits in existing heater fireboxes has typically not met test stand performance, with actual NO_X emissions rates from 20% to 40% higher than expected.

In Permit No. 2002-476-C (PSD), NO_X emissions from H-0001 were limited to 38 TPY based on a BACT limitation of 0.05 lb/MMBtu. ConocoPhillips had opted to install the ULNB in Heater H-0048 and include the subsequent NO_X reductions as part of their NO_X reduction plan for the Consent Decree. NO_X emissions for H-0048 were limited to 37 TPY, based on expected emissions of 0.04 lb/MMBtu from the ULNB.

In the application for modification M-1, ConocoPhillips requested an increase in the NO_X emission limits for H-0001 to 46 TPY based on demonstrated NO_X emissions of 0.06 lb/MMBtu. This was an increase in NO_X emissions of about 8 TPY from the previous permit. The BACT determination remained installation of ULNB, but at a higher emission rate limit of 0.06 lb/MMBtu. Because BACT was changed from the original determination and because allowable emissions increased from those in the original PSD permit, permit modification M-1 was subject to Tier II permit requirements and underwent public and EPA review.

ConocoPhillips opted not to include the NO_X reductions from installation of ULNB in H-0048 as part of their NO_X reduction plan for the Consent Decree. As such, installation of ULNB was no longer a requirement of any applicable federal or state rule, or any Consent Decree requirement. ConocoPhillips requested an increase in the NO_X limitations for H-0048 to 74 TPY based on demonstrated NO_X emissions of 0.07 lb/MMBtu. This was an increase in NO_X emissions of 37 TPY from those in Permit No. 2002-476-C (PSD). Also, because the H-0048 modification was no longer a requirement of the Consent Decree, a previous specific condition limiting CO emissions to 0.04 lb/MMBtu was not a requirement. ConocoPhillips requested to raise the limit on CO emission to 0.06 lb/MMBtu, which is less than the CO limit of 0.0824 lb/MMBtu that was in effect for H-0048 prior to issuance of Permit No. 2002-476-C PSD.

The new future-potential NO_X emission rate for both H-0001 and H-0048 was still less than the past-actual NO_X emission rates used in Permit No. 2002-476-C (PSD) of 173 TPY and 102 TPY, respectively. Therefore, the past-actual-to-future-potential NO_X emission change for each heater was still less than zero.

- H-0001: 46 TPY - 173 TPY = -127 TPY
- H-0048: 74 TPY - 102 TPY = - 28 TPY

The H-0001 and H-0048 NO_X emission reductions used in Permit No. 2002-476-C PSD (-135 TPY and - 66.5 TPY, respectively) were the result of Consent Decree compliance, and were not creditable for PSD netting calculations. Therefore, the past-actual-to-future-potential NO_X emission changes for these heaters were set at zero. The past-actual-to-future-potential NO_X emission changes remained as zero in permit modification M-1; therefore, the PSD netting calculations for NO_X in Permit No. 2002-476-C PSD remained unchanged.

The new future-potential CO emission rate for H-0048 of 63.5 TPY was still less than the past-actual CO emission rate used in Permit No. 2002-476-C (PSD) of 67 TPY. Therefore, the past-actual-to-future-potential CO emission change for H-0048 was still less than zero.

- H-0048: 64 TPY - 67TPY = -3 TPY

The H-0048 CO emission reductions used in Permit No. 2002-476-C PSD (-25 TPY) were the result of Consent Decree compliance, and were not creditable for PSD netting calculations. Therefore, the past-actual-to-future-potential CO emission change for H-0048 was set at zero. The past-actual-to-future-potential CO emission change remained zero in permit modification M-1: therefore, the PSD netting calculations for CO in Permit No. 2002-476-C PSD remained unchanged.

ConocoPhillips also requested that heater H-0046, the other No. 2 CRU Reactor Preheater, and H-0047, the No. 4 Hydrotreater Heater, be made subject to 40 CFR Part 60, Subpart J as those heaters share the fuel gas heater with H-0048 and are required to be subject to Subpart J by the Consent Decree.

In summation, the following modifications were made to the original construction permit:

- Increased the 365-day rolling average NO_X emission limit for H-0001 in Specific Condition No. 1.A. to 10.5 lb/hr and the TPY limit to 46.0.
- Increased the 365-day rolling average NO_X emission factor limit for H-0001 in Specific Condition No. 1.A.iii to 0.060 lb/MMBtu.
- Increased the 365-day rolling average NO_X emission limit for H-0048 in Specific Condition No. 1.A. to 16.9 lb/hr and the TPY limit to 74.0.
- Increased the 365-day rolling average CO emission limit for H-0048 in Specific Condition No. 1.A. to 14.5 lb/hr and the TPY limit to 63.5.
- Removed item iii for H-0048 in Specific Condition No. 1.A., which read "The heater shall be constructed with Next Generation Ultra Low NO_X Burners (ULNB) with NO_X emission limited to 0.035 lb/MMBtu, 365-day rolling average."
- Removed item iv for H-0048 in Specific Condition No. 1.A., which read "Upon installation of Next Generation Ultra Low NO_X Burners (ULNB), CO emissions shall be limited to 0.060 lb/MMBtu on a 24-hour rolling average basis and 0.04 lb/MMBtu, 365-day rolling average."

- Revised item ix for H-0048 in Specific Condition No. 1.A to include H-0046 and H-0047 as being subject to 40 CFR Part 60, Subpart J.
- Addressed applicability requirements of CFR 40 Part 63, Subpart DDDDD for the process heaters.

C. Requested Modification (M-2)

For this modification, ConocoPhillips has requested the following changes to the permit. All of the requested changes are minor modifications and all, except the last one listed, are requirements of the Consent Decree. As such, these modifications will be processed as Tier I and not subject to public review.

- Add a new specific condition for Heater H-0048 limiting CO emissions to 0.04 lb/MMBtu on a 365-day rolling average and to 0.06 lb/MMBtu on a 24-hour basis, with certain exclusions regarding emissions at firing rates less than 30% of maximum firing rate, or during periods of catalyst regeneration, and emissions during startup, shutdown, and malfunction as specified in the Consent Decree.
- Reduce the CO emission limits for heater H-0048 to 9.7 lb/hr and 42.3 TPY from 14.5 lb/hr and 63.5 TPY.
- Add a new specific condition for heater H-0048 to include a 365-day rolling average NO_X emission limit of 0.07 lb/MMBtu. Existing lb/hr and TPY limits for H-0048 are already based on this emission rate, so those limits are not affected.
- Revise Specific Condition 1.A.H-0001.iii to include certain exclusions regarding emissions at firing rates less than 30% of maximum firing rate and emissions during startup, shutdown, and malfunction as specified in the Consent Decree.
- Remove references to heaters H-46 and H-47 in Specific Condition No. 1.A.H-0048.vi. Heater H-47 has been permanently shutdown and heater H-46 has redundant specific conditions in Permit No. 91-043-O (M-7).

SECTION II. PROCESS DESCRIPTION

The Refinery uses various distillation, cracking, and treatment processes to separate and transform the crude into various hydrocarbon groups so that they may be used, combined or further treated to create gasoline, fuel oils (e.g., diesel, jet fuel, kerosene, and heating oil), liquid petroleum gas (LPG), residual oils and other petrochemical feedstocks. The following sections describe the primary process units affected by this project and the benefits of the proposed upgrades.

A. The Number 1 Crude Topping Unit

The No. 1 Crude Topping Unit (No. 1 CTU) is one of three crude units that process raw crude oil in parallel. Crude topping units are the first major refinery process that contacts incoming crude oil. The No. 1 CTU fractionates crude oil into several different boiling fractions that are then sent to downstream units for further processing. The No. 1 CTU can be divided into five basic sections: Preheat Train/Desalter, Preflash Drum, Crude Tower, Tar Stripper, and Vacuum Tower.

The desalted crude is passed through heat exchangers and on to the Preflash Drum section. In the Preflash Drum section, the lighter components of the heated crude vaporize while the long-chain hydrocarbons (i.e., bottoms) are transferred through heat exchangers to the Crude Tower section. Heater H-0001 heats the crude entering the Crude Tower section before entering the crude distillation tower. The distillation tower separates the heated feed into the following intermediates: overhead vapor, light straight run (LSR) gasoline, naphtha, kerosene, heating oil distillate, atmospheric gas oil, and reduced crude.

Feed to the Tar Stripper Section is reduced crude off the bottoms of the crude tower. The stream is further heated before entering the Tar Stripper Tower. The Tar Stripper Tower uses multistage atmospheric flash to further remove atmospheric gas oils, designated “light gas oil” and “heavy gas oil,” from the feed. The bottoms stream flows to the vacuum tower. Feed to the vacuum unit is heated in heater H-0015 before entering the vacuum tower. The vacuum tower is the end of the distillation process and separates the feed into light vacuum gas oil, heavy vacuum gas oil, and residual heavy oil (vacuum residuum). The vacuum residuum material is routed to the No. 7 Coker.

B. Coking Process

The No. 7 Coker unit (“Coker”) processes vacuum residuum, decant oil, heavy gas oil, and slop oil into coker wet gas, coker gasoline, light coker gas oil (LCGO), heavy coker gas oil (HCGO), and anode-grade coke. The Coker processes vacuum residuum streams from the No. 2 CTU and No. 4 CTU as well as the No. 1 CTU.

Coker feed is heated by a series of heat exchangers in the Feed and Preheat section. Preheated feed then enters the coker de-fractionator (“bubble tower”) in the Fractionator and Overhead Section, entering the flash zone. Vapors rising up the bubble tower from the flash zone are quenched by a series of pumparound cooling loops, the first of which is the flash zone gas oil (FZGO) circuit. It is followed by the HCGO and LCGO circuits, from which intermediate streams are drawn off for further processing. Vapors reaching the top of the bubble tower are partially condensed against external cooling to form two additional intermediate products, coker gasoline and coker wet gas. Each of these streams is sent to other units for further processing.

Extremely heavy oil exiting the bubble tower bottom is pumped to the Furnace and Coke Drums section. Two furnaces, H-0028 and H-0029, further heat the stream before it is charged to one of the two coke drums where thermal cracking takes place. The coke drums operate in alternating batch service to produce solid anode-grade petroleum coke.

Vapors resulting from the thermal cracking during a drum-fill phase of the cycle are recycled back to the bubble tower for recovery of condensable products or captured in the overhead wet gas stream. During other drum cycle phases (warming and quenching) vapors exiting the top of the drums enter the Closed Blowdown Section for liquids recovery before capture by the Flare Gas Recovery Unit and processing for refinery fuel gas.

C. The No. 2 Catalytic Reforming Unit

The No. 2 Catalytic Reforming Unit (CRU) converts low octane naphtha into high octane reformate without the use of octane enhancing additives such as lead. The No. 2 CRU also removes sulfur-containing compounds by hydrogenation. The naphtha processed in the No. 2 CRU comes from the crude units, the Sat Gas Plant, Coker, the No. 4 HDT, and the No. 6 HDT.

The No. 2 CRU contains three major operating sections. In the hydrodesulfurization (HDS) section, hydrogen is used to convert sulfur compounds to H_2S. Naphtha from this section goes to the reforming section where reactors catalytically convert low octane components to high-octane components, producing unstabilized reformate and hydrogen under a hydrogen atmosphere. Compressor C-30 supplies sweet hydrogen-rich gas for combination with the naphtha to form reactor feed. Four of the five cells in heater H-0048 preheat the feed before entering the reactors. The unstabilized reformate goes to the fractionation section where light components are separated. The reformate product is sent to storage for gasoline blending.

D. The No. 7 Hydrotreater Unit

The No. 7 Hydrotreater (No. 7 HDT) uses hydrogen to catalytically remove sulfur and nitrogen compounds from hydrocarbon streams. The No. 7 HDT takes stabilized light straight run (LSR), casing head gasoline, and sweet hydrogen from the No. 2 Catalytic Reforming Unit (CRU) or No. 3 CRU, and produces hydrotreated gasoline for gasoline blending, naphtha for the No. 2 CRU and No. 3 CRU, and butane-and-lighter gases that go to the Sat Gas Plant. The primary process equipment includes a naphtha splitter, reactor, and product stabilizer.

SECTION III. PROJECT DESCRIPTION

This project impacted emissions in the following process areas: No. 1 CTU, Coker Process Unit, No. 2 CRU, and No. 7 HDT. The following sections describe each of the modifications in detail.

A. No. 1 CTU Upgrade

The purpose of the No. 1 CTU upgrade project was to increase the Refinery's ability to handle price-advantaged crude, thus lowering feedstock costs. The project also increased crude processing rates. Price-advantaged crudes have a larger portion of the crude assay residing in the gas oil boiling range (approximately 700-1050 °F). Separation between light vacuum gas oil (LVGO), heavy vacuum gas oil (HVGO), and vacuum residuum ("resid") occurs in the crude vacuum unit. The vacuum unit's ability to handle these types of crude was previously limited by the vacuum tower size and amount of heat input available from heater H-0015.

To increase recovery of LVGO and HVGO, the existing vacuum tower and heater H-0015 were replaced. Some peripheral equipment such as pumps, filters, inlet/outlet piping, transfer lines, valves, flanges, pressure relief devices, sampling systems, miscellaneous piping connections, tower trays, drums, heat exchangers, air coolers, instrumentation, and utilities (e.g., electrical, steam, and air systems) were upgraded or added. Other installations included a new steam ejector vacuum system for the vacuum tower overhead and a new steam line for supply of additional steam to the atmospheric distillation tower and new vacuum system. General hydraulic debottlenecking was a result of these and other miscellaneous modifications.

The project also included work on heater H-0001. The project objective was to increase heater capacity, reduce NO_X emissions per the Consent Decree, and to improve safety. Work on H-0001 to increase heater capacity involved removing some baffles in the convection section. Work on H-0001 to reduce NO_X emissions included replacement of the burners with Ultra Low NO_X Burners (ULNB), replacement of the combustion air ducts, installation of a new Continuous Emissions Monitoring System (CEMS), installation of a new fuel gas filter/coalescer, and sealing air leaks. Work to improve safety included metallurgy upgrade of the steam coil to remove mechanical deficiencies, refractory repair, and modifications to increase natural draft capacity. Natural draft is the emergency back-up operating mode when air preheater fans trip-out. Safe design practices require the natural draft capacity to be equal to air preheat capacity. H-0001 natural draft capacity was previously less than that in the preheat air (normal operating) mode, which, in an emergency transition to natural draft, created a risk of explosion of un-combusted fuel downstream of the radiant box.

Installation of the CEMS required by the Consent Decree included attachment of nozzles, an access platform, and cable tray to the stack. Previous inspections of the H-0001 stack had shown that the existing shell was unsuitable for welding due to thinning from corrosion. The thinning was so extensive that the recommendation was made that the stack be replaced at the 2004 turnaround. Given the necessity of replacing the stack for structural reasons, the opportunity was taken to upsize the stack in order to address the safety concerns mentioned.

Crude distillation units like the No. 1 CTU are the first major refinery processes that contact incoming crude oil. The various fractions separated by the No. 1 CTU are charged to downstream units for further processing. Therefore, process rate increases made in the No. 1 CTU also affect process rates for some downstream units. Many of the affected downstream units utilize fuel-fired furnaces to generate process heat. Since process rate increases are assumed to correlate directly with fuel usage in fuel-fired furnaces, the project evaluation included attributable emissions increases from furnaces in the following process units: Saturated Gas Plant, Butamer, No. 2 Reformer, No. 4 Hydrotreater, No. 5 Hydrotreater, No. 6 Hydrotreater, No. 7 Hydrotreater, No. 7 Coker, No. 5 Fluid Catalytic Cracking Unit, and Alkylation Unit.

The increased percentage of price-advantaged crudes, and the larger vacuum unit's ability to fractionate gas oil out of resid, resulted in a heavier (higher average boiling point) feed to the coker. Anode-grade petroleum coke production increased due to the shift in Coker feed properties process rates. This increase affected the solid petroleum coke loading rates at the Coke Pad and Loading Facility. Changes to the No. 1 CTU also affected raw crude and product storage tanks. Steam production increased as well, which affected the main refinery steam cogeneration system.

B. Coker Process Unit Modifications Project

The purpose of the Coker Process Unit Modifications Project was to debottleneck the Coker unit, which resulted in increased capacity. The project did not physically modify Coker heaters H-0028 and H-0029. New installations included bubble tower flash zone spray nozzles, bubble tower flash zone tray quench/flush, and coke drum continuous level indicators. Other Coker equipment projects included modifications to the Coker naphtha stabilizer tower trays and packing, Coker naphtha stabilizer reboiler, bubble tower reflux drum, fresh feed pumps, air coolers, and transfer lines. Some peripheral equipment such as pumps, filters, inlet/outlet piping, transfer lines, valves, flanges, pressure relief devices, sampling systems, miscellaneous piping connections, tower trays, drums, heat exchangers, air coolers, instrumentation, and utilities (e.g., electrical, steam, and air systems) were upgraded or added. General hydraulic debottlenecking resulted from these and other miscellaneous modifications.

Due to the increase in Coker process capacity, actual fuel usage by heaters H-0028 & H-0029 increased. Associated emission increases are included in the project emissions calculations.

C. H-0048 NO_X Reduction and MI Remediation Project

The purpose of this Project was not to increase the capacity of heater H-0048 (reactor preheater for the No. 2 CRU), but to reduce NO_X emissions by installing ULNB and to address mechanical integrity issues with the heater. At this time, ConocoPhillips is not including the NO_X reductions from the H-0048 modifications as part of their NO_X reduction plan for the Consent Decree; therefore, NO_X and CO emission rates in lb/MMBtu are not limited by any applicable federal or state requirement not previously in effect, or by the Consent Decree. The project involved modifying or replacing the floor in all 5 cells in H-0048 to accommodate new ULNB, installing a fuel gas coalescer, and installing a new Continuous Emissions Monitoring System (CEMS). The project also involved the installation of new oxygen analyzers, the replacement of some process convection tube rows with a superior metallurgy, replacement of some or all of the radiant refractory system, and replacement of some or all outer walls of the furnace that were not replaced in the 1999 unit shutdown. The project also involved modifying or repairing any of the three stages of flue gas dampers. Minor thermal and/or hydraulic debottlenecking was a result of these modifications and repairs.

D. No. 7 HDT Charge Pump Modification Project

The purpose of this project was to increase the charge rate to the No. 7 HDT. This was done by increasing the size of the motor controller heater for the charge pumps to the No. 7 HDT. The project also included general hydraulic debottlenecking. The project did not involve any work to heater H-0011, the heater for the No. 7 HDT.

SECTION IV. PROJECT EMISSIONS (Original PSD Permit)

This section presents the emission calculation methodology used to determine PSD applicability for the modified and associated units; including process heaters, equipment leaks, storage tanks, and emissions associated with increased steam production.

A PSD netting analysis was performed based on suggested emissions netting procedures in the Draft Environmental Protection Agency (U.S. EPA) "New Source Review (NSR) Workshop Manual." A six-step procedure (summarized below) was used for determining the net emissions change.

1. Emission Increases from the Project - Determine the emission increases from the project, including any associated emissions increases (i.e., debottlenecking emissions). If increases are significant, then proceed, if not, the project is not subject to PSD review.
2. Contemporaneous Period - Determine the beginning and ending dates of the contemporaneous period as it relates to the project.
3. Emissions Increases and Decreases During the Contemporaneous Period - Determine which emissions units at the facility experienced or will experience a creditable increase or decrease in emissions during the contemporaneous period. This step also includes any emissions decreases from the project.
4. Creditable Emissions Changes - Determine which contemporaneous emissions changes are creditable.
5. Amount of the Emissions Increase and Decrease - Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.
6. PSD Review - Sum all contemporaneous and creditable increases and decreases with the emissions changes from the project to determine if a significant net emissions increase will occur.

The following sections detail each of the steps outlined above.

Emission Increases from the Project

In this step, the emissions increases from the project were calculated on a pollutant-by-pollutant basis. These increases include both project emissions and emissions from sources associated with the project (e.g., emissions increases from debottlenecking). Emission decreases are not considered at this step.

New and Modified Process Heaters

Process heater H-0015 was replaced as part of this modification with a larger 106.7 MMBtu/hr (HHV basis) process heater (EU ID is H-0016).

Emissions of PM_{10} and VOC were calculated using AP-42 (7/98), Tables 1.4-1 and 1.4-2, emission factors for natural gas combustion. The CO and NO_X emission factors for H-0016 are based on vendor guarantees for ULNB. Emission factor for SO_2 is based on NSPS Subpart J-allowable H_2S content of 0.10 grains per dry standard cubic foot (grains/dscf) (160 parts per million on a volumetric basis [ppmv]) and a conservative fuel gas heating value of 700 BTU/SCF.

Emission Unit	Maximum Firing Rate, MMBtu/hr	Pollutant	Emission Factors, lb/MMBTU	Emissions	
				lb/hr	TPY
H-0016, No. 1 CVU Charge Heater	106.7	CO	0.0400	4.27	18.69
		PM_{10}	0.0075	0.80	3.48
		NO_X	0.0350	3.73	16.36
		SO_2	0.0384	4.10	17.95
		VOC	0.0054	0.58	2.52

Heater H-0001 was modified as a result of the proposed project. Therefore, emissions were based on an actual-to-future potential comparison. The emission increases were calculated by subtracting the past two-year (2000 and 2001) actual average emissions from the future potential to emit (PTE).

Heater H-0001, No. 1 CTU Crude Charge Heater, had been permitted under Permit No. 2001-311-C. It was identified as a source to be controlled as part of the Consent Decree NO_X control plan. Permit No. 2001-311-C specified that ULNB technology be installed on heater H-0001 after 12/31/04 or the next scheduled turnaround for the No. 1 CTU, whichever came first. Since the No. 1 CTU upgrade project occurred during the next scheduled turnaround, heater H-0001 was retrofitted with ULNB technology with NO_X emissions of 0.060 lb/MMBtu. Because of its operation mode, this heater cannot reduce NO_X to the typical level of 0.035 lb/MMBtu. Since the installation of the new burners is to comply with the Consent Decree, emission decreases of NO_X and CO were not considered creditable for PSD netting purposes. As a result of Permit No. 2002-476-C PSD, Permit No. 2001-311-C was made null and void.

The maximum future firing rate (MMBtu/hr) of heater H-0001 is based on the completed modifications and the Higher Heat Value (HHV). Emissions of PM_{10} and VOC are based on AP-42 Section 1.4 (7/98), Tables 1.4-1 and 1.4-2 emission factors. Emissions of NO_X and CO are based on measured achievable rates from the recently installed ULNB.

The emission factors for past actual SO_2 are based on the actual H_2S content of the fuel gas and actual heating value with future potential based on NSPS Subpart J-allowable H_2S content of 160 ppm_v and a worst-case heating value of 700 btu/scf.

H-0001, Crude Charge Heater, 175 MMBtu/hr (HHV Basis)				
	Pollutant	**Emission Factors, lb/MMBTU**	**Emissions**	
			lb/hr	**TPY**
Future Potential Emissions	CO	0.0400	7.00	30.66
	PM_{10}	0.0075	1.31	5.75
	NO_X	0.0600	10.50	46.00
	SO_2	0.0384	6.72	29.43
	VOC	0.0054	0.95	4.14
2-Year Actual Emissions	CO	0.0824	-	59.20
	PM_{10}	0.0075	-	5.40
	NO_X	0.2000	-	173.00
	SO_2	-	-	6.60
	VOC	0.0054	-	3.90
Emission Increases	CO		-	0.00
	PM_{10}		-	0.35
	NO_X		-	0.00
	SO_2		-	22.83
	VOC		-	0.24

Equipment Leaks

The project will result in an increase in VOC emissions from equipment leaks (part of EU ID FUG) due to the installation of equipment such as flanges, valves, compressors, drains, and pumps. Fugitive emitting equipment will be associated with the No. 1 CTU, No. 7 Coker, and No. 2 CRU. The emissions increases for equipment leaks are calculated using design-basis fugitive counts in concert with emission factors that were developed specifically for the Refinery.

Fugitive Components, FUG	**Number**	**Emission Factor, lb/hr/source**	**VOC Emissions**	
			lb/hr	**TPY**
GGG Components Added				
Gas Valves	224	0.00253	0.567	2.48
Light Liquid Valves	96	0.00468	0.449	1.97
Heavy Liquid Valves	420	0.00051	0.214	0.94
Flanges	2664	0.00013	0.346	1.52
Light Liquid Pumps	1	0.04509	0.045	0.20
Heavy Liquid Pumps	4	0.04718	0.189	0.83
Gas Compressors	0	0.50265	0.00	0.00
Gas Relief Valves to Atmosphere	0	0.22928	0.00	0.00
Gas Relief Valves to Flare	1	0.00459	0.005	0.02
Sample Stations	0	0.03307	0.00	0.00
Controlled Process Drains	3	0.03500	0.105	0.46
Controlled Junction Boxes	0	0.07000	0.00	0.00
Totals			**1.92**	**8.42**

<u>Associated Process Heaters</u>

Associated emissions were included in this permit solely for the purpose of verifying PSD applicability. The project did not involve physical modifications to any associated emission units, and these emission units will continue to operate in compliance with currently applicable rules, regulations, and permit conditions.

The emission increases from the associated process heaters were calculated by subtracting the past two-year (2000 and 2001) actual emissions from the future potential to emit (PTE), with the exception of heater H-5001. Actual emissions from H-5001 were based on the average emissions from reporting years 1999 and 2000, since this unit was included in the 2001 Refinery turnaround and experienced a significant outage during 2001.

During this project, heater H-0048 was retrofitted with ULNB; however, at this time, ConocoPhillips is not including the NO_X emission decreases as part of their NO_X reduction plan for the Consent Order. Therefore, there are no specific NO_X or CO emission rates that must be met. Since the heater changes are required to reduce NO_X emissions and address maintenance needs, it is not considered modified. Emissions of NO_X and CO are based on demonstrated performance of the new ULNB.

The future firing rate (MMBtu/hr) of the associated heaters is based on current permit limits or, in the absence of permit limits, the maximum demonstrated rate (MDR) unless otherwise noted. Emissions of PM_{10} and VOC are based on AP-42 Section 1.4 (7/98), Tables 1.4-1 and 1.4-2 emission factors. Emissions of NO_X and CO are based on permitted emission limits or AP-42 Section 1.4 (7/98), Tables 1.4-1 and 1.4-2.

The emission factors for past actual SO_2 are based on the actual H_2S content of the fuel gas and actual heating value with future potential based on permitted emission limits or NSPS Subpart J-allowable H_2S content of 160 ppm_v and a worst case heating value of 700 Btu/scf.

The associated emissions for heater H-6007 are based on existing burners, even though ULNB will be installed as per Permit No. 2003-336-C (M-1) PSD.

H-0048, No. 2 CRU Reactor Preheater, 241.4 MMBtu/hr (HHV Basis)				
	Pollutant	**Emission Factors, lb/MMBtu**	**Emissions**	
			lb/hr	**TPY**
Future Potential Emissions	CO	0.0600	14.50	63.50
	PM_{10}	0.0075	1.80	7.88
	NO_X	0.0700	16.90	74.01
	SO_2	0.0384	9.27	43.35
	VOC	0.0054	1.30	5.70
2-Year Actual Emissions	CO	0.0824	-	67.00
	PM_{10}	0.0075	-	6.10
	NO_X	0.1250	-	101.60
	SO_2	-	-	1.10
	VOC	0.0054	-	4.40

Emission Increases	CO		-	0.00
	PM_{10}		-	1.78
	NO_X		-	0.00
	SO_2		-	42.25
	VOC		-	1.30

Emissions Unit	Pollutant	2-year Average Emissions, TPY	Future Potential, TPY	Associated Emissions, TPY
H-0005, No. 1 CTU Crude Charge Heater	NO_X	22.10	37.00	14.90
	SO_2	2.10	16.00	13.90
	CO	18.60	31.00	12.40
	VOC	1.20	2.00	0.80
	PM_{10}	1.70	3.00	1.30
H-0028, No. 7 Coker Process Heater	NO_X	53.30	78.00	24.70
	SO_2	0.70	24.00	23.30
	CO	34.20	47.00	12.80
	VOC	2.20	3.04	0.84
	PM_{10}	3.10	5.00	1.90
H-0029, No. 7 Coker Process Heater	NO_X	18.40	32.19	13.79
	SO_2	0.40	10.00	9.60
	CO	16.60	27.05	10.45
	VOC	1.10	1.77	0.67
	PM_{10}	1.50	2.45	0.95
H-0023, No. 5 HDT Charge Heater	NO_X	10.20	31.44	21.24
	SO_2	0.20	7.00	6.80
	CO	8.60	18.90	10.30
	VOC	0.60	1.24	0.64
	PM_{10}	0.80	1.71	0.91
H-0047, No. 4 HDS Charge Heater	NO_X	5.60	10.00	4.40
	SO_2	0.10	5.00	4.90
	CO	4.80	9.00	4.20
	VOC	0.30	0.54	0.24
	PM_{10}	0.40	1.00	0.60
H-7501, No. 6 HDT Reactor Charge Heater	NO_X	8.00	18.00	10.00
	SO_2	0.10	5.34	5.24
	CO	4.30	5.39	1.09
	VOC	0.40	0.61	0.21
	PM_{10}	0.50	1.19	0.69
H-0046, No. 2 CRU Charge Heater	NO_X	10.20	21.00	10.80
	SO_2	0.10	9.00	8.90
	CO	8.60	18.00	9.40
	VOC	0.60	1.13	0.53
	PM_{10}	0.80	2.00	1.20
H-6007, No. 3 CRU Reactor Preheater	NO_X	96.10	153.30	57.20
	SO_2	0.70	29.47	28.77
	CO	28.80	63.16	34.36
	VOC	1.90	4.13	2.23
	PM_{10}	2.60	5.71	3.11

Emissions Unit	Pollutant	2-year Average Emissions, TPY	Future Potential, TPY	Associated Emissions, TPY
H-6012, No. 3 CRU Desulfurizer Preheater	NO_X	8.20	11.00	2.80
	SO_2	0.20	5.00	4.80
	CO	6.90	9.00	2.10
	VOC	0.50	0.59	0.09
	PM_{10}	0.60	1.00	0.40
H-6013, No. 3 CRU Reactor Preheater	NO_X	15.70	19.91	4.21
	SO_2	0.30	12.75	12.45
	CO	13.20	13.27	0.07
	VOC	0.90	1.79	0.89
	PM_{10}	1.20	2.47	1.27
H-0010, Saturated Gas Plant Naphtha Reboiler	NO_X	5.50	18.03	12.53
	SO_2	0.40	7.54	7.14
	CO	4.70	15.16	10.46
	VOC	0.30	0.99	0.69
	PM_{10}	0.40	1.38	0.98
H-0011, No. 7 HDT Heater	NO_X	3.90	6.31	2.41
	SO_2	0.20	2.26	2.06
	CO	2.40	4.33	1.93
	VOC	0.20	0.28	0.08
	PM_{10}	0.20	0.39	0.19
H-0057, Alky Depropanizer Heater	NO_X	20.20	30.00	9.80
	SO_2	1.60	13.00	11.40
	CO	15.50	25.00	9.50
	VOC	1.00	1.62	0.62
	PM_{10}	1.40	3.00	1.60
H-0058, Alky Depropanizer Heater	NO_X	15.30	21.00	5.70
	SO_2	1.10	9.00	7.90
	CO	11.30	18.00	6.70
	VOC	0.70	1.15	0.45
	PM_{10}	1.00	2.00	1.00
H-5001, No. 5 FCC Preheater	NO_X	68.60	145.00	76.40
	SO_2	0.70	22.00	21.30
	CO	20.60	44.00	23.40
	VOC	1.30	2.83	1.53
	PM_{10}	1.90	4.00	2.10
H-0059, Alky Depropanizer Heater	NO_X	20.80	29.00	8.20
	SO_2	1.60	12.00	10.40
	CO	17.50	25.00	7.50
	VOC	1.10	1.58	0.48
	PM_{10}	1.60	3.00	1.40

	Pollutant			TPY
Total Associated Heater Emission Increases	**NO_X**			**279.08**
	SO_2			**221.11**
	CO			**156.66**
	VOC			**12.29**
	PM_{10}			**21.38**

No. 5 Fluid Catalytic Cracking Unit Emissions

The project will cause an increase in emissions from the No. 5 Fluid Catalytic Cracking Unit (FCCU) due to increased crude processing. The associated emission increase is based on subtracting the past two-year actual average emissions from the future emission rate. This unit was included in the 2001 Refinery turnaround; therefore, reporting years 1999 and 2000 were used for determining the past two years actual average emissions. Actual and future potential emissions for this unit are based on actual and future potential process rates (barrels per day [bpd]), recent emissions testing data, and permit limits.

Pollutant	Existing Emissions, TPY	Potential Emissions, TPY	Emission Changes, TPY
NO_X	233.09	235.04	1.95
SO_2	1191.61	1201.62	10.01
CO	17.72	80.00	62.28
VOC	--	--	--
PM_{10}	328.72	341.53	12.81

Coke Pad Emissions

The Coke Pad is currently operating under Permit No. 97-269-O. Specific Condition No. 1 limits PM_{10} emissions to 9.094 TPY, while Specific Condition No. 2 limits annual coke throughput to 475,000 TPY. Recently, ConocoPhillips has refined the emission estimation procedure for the Coke Pad. The refined methodology uses the same AP-42 equations as the original permit application; however, the emission sources are defined based on actual operations. Actual emissions are based on calendar years 2000 and 2001 and the refined methodology.

Pollutant	Existing Emissions, TPY	Potential Emissions, TPY	Emission Changes, TPY
PM_{10}	1.29	1.60	0.31

Cogeneration Unit Duct Burner Emissions

This project will result in an increased steam demand from the No. 1 and No. 2 Cogeneration Duct Burners (COG-1DB and COG-2DB). These units are currently operating under Permit No. 95-158-O (M-3). The project requires an additional 15,000 lb/hr of 175-psia steam, which results in an additional energy requirement of 153,081 MMBtu/yr. Based on the operation of the Refinery, was assumed that the additional steam will be supplied by the cogeneration units.

While other units at the Refinery may operate occasionally, the primary source of steam at the facility is the cogeneration units.

Emission factors for the duct burners are based on permitted emission limitations. The emission factors are as follows: 0.04 lb CO/MMBtu, 0.02 lb PM_{10}/MMBtu, 0.20 lb NO_X/MMBtu, and 0.05 lb VOC/MMBtu. The incremental increase in SO_2 emissions are based on the listed heat requirement and an actual H_2S content of 14 ppmv.

Emission Unit	Pollutant	Emission Increase, TPY
Duct Burners	NO_X	15.31
	CO	3.06
	VOC	3.83
	SO_2	0.23
	PM_{10}	1.53

Cooling Tower and Wastewater Emissions

The project will increase emissions from main cooling tower CT-10 due to an increased recirculating flow rate. The project is expected to increase recirculating flow rate by 200 gallons per minute (gpm). Emissions for PM_{10} are calculated using CT-10 design parameters. The values used in the emission calculations are total dissolved solids (TDS) concentration (850 parts per million [ppm]) and the drift rate (0.002%). Emissions for VOC are calculated using the controlled emission factor for petroleum refinery cooling towers presented in AP-42 (1/95), Table 5.1-2.

$$PM_{10} \text{ emissions (tpy)} = \left(\frac{0.002}{100}\right) x \left(\frac{200 \text{ gal}}{\text{min}}\right) x \left(\frac{60 \text{ min}}{\text{hr}}\right) x \left(\frac{8.34 \text{ lb}}{\text{gal}}\right) x \left(\frac{850 \text{ ppm}}{10^6}\right) x \left(\frac{8{,}760 \text{ hours}}{\text{year}}\right) x \left(\frac{\text{ton}}{2{,}000 \text{ lb}}\right) = 0.01 \text{ tpy}$$

$$\text{VOC emissions (tpy)} = \left(\frac{0.7 \text{ lb}}{10^6 \text{ gal}}\right) x \left(\frac{200 \text{ gal}}{\text{min}}\right) x \left(\frac{60 \text{ min}}{\text{hr}}\right) x \left(\frac{8{,}760 \text{ hr}}{\text{yr}}\right) x \left(\frac{\text{ton}}{2{,}000 \text{ lb}}\right) = 0.04 \text{ tpy}$$

Emissions from additional wastewater as a result of the project were also addressed. It was conservatively assumed that the project would result in additional emissions of 5% above historical emissions. This would equate to 0.96 TPY of VOC.

Associated Storage Tank Emissions

The project will result in increased crude processing, gasoline, and diesel production. The estimated future No. 1 CTU crude processing rate of 110,000 bbl/day (bpd) represents an increase of 33,194 bpd from the past two-year average (2000 and 2001) crude production. It was conservatively assumed that the increased throughput would occur in one storage tank for each type of affected tank and for each type of product produced. The types of storage tanks affected by the project are raw crude storage, blended gasoline and blended diesel storage, and base component storage.

Emissions were calculated based on the anticipated throughput for the assumed tanks using U.S. EPA's TANKS 4.09 program. The total increase in VOC emissions is expected to occur due to the increased working losses for each storage tank.

Emission Unit	Stored Material	Associated VOC Increases, TPY
Raw Crude/Product Storage		
T-38	Raw Crude	5.73
T-114	Blended Gasoline	0.51
T-168	Blended Diesel	0.58
Gasoline Blending		
T-163	LSR	0.02
T-165	Alkylate	0.02
T-162	Light FCC Gasoline	0.09
T-152	Heavy FCC Gasoline	0.06
T-153	LS Reformate	0.08
Diesel Blending		
T-131	1, 2, & 4 HOD & 4 FCC LCO	0.46
T-61	1, 2 & 4 CTU Kerosene	0.04
T-641	4 HDT LS Kerosene	0.06
T-135	6 HDT Distillate	0.94
TOTAL		**8.59**

Total Project Emissions

The following table lists total emissions associated with the described project.

Project Total Emissions										
	NO_X		CO		VOC		SO_2		PM_{10}	
Source	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-0016	3.73	16.36	4.27	18.69	0.58	2.52	4.10	17.95	0.80	3.48
H-0001	-	0.00	-	0.00	-	0.24	-	22.83	-	0.35
Fugitive	-	-	-	-	1.92	8.42	-	-	-	-
Heaters	-	279.08	-	156.66	-	12.29	-	221.11	-	21.38
No. 5 FCCU	-	1.95	-	62.28	-	-	-	10.01	-	12.81
Coke Pad	-	-	-	-	-	-	-	-	-	0.31
Duct Burners	-	15.31	-	3.06	-	3.83	-	0.23	-	1.53
Cooling Tower	-	-	-	-	-	0.04	-	-	-	0.01
Tanks	-	-	-	-	-	8.59	-	-	-	-
Wastewater	-	-	-	-	-	0.96	-	-	-	-
TOTAL	**-**	**312.70**	**-**	**240.69**	**-**	**36.89**	**-**	**272.13**	**-**	**39.87**

HAP Emissions

The refinery is an existing major source of HAP emissions and the majority of the process units for this project are subject to National Emission Standards for Hazardous Air Pollutants (NESHAPs), 40 CFR Part 63, Subpart CC.

SECTION V. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

This section presents the methodology used to determine PSD applicability for the project. The steps used are described following:

1. Emission Increases from the Project - Determine the emission increases from the project, including any associated emissions increases (i.e. debottlenecking emissions). If increases are significant, then proceed, if not, the project is not subject to PSD review.
2. Contemporaneous Period - Determine the beginning and ending dates of the contemporaneous period as it relates to the project.
3. Emissions Increases and Decreases During the Contemporaneous Period - Determine which emissions units at the facility experienced or will experience a creditable increase or decrease in emissions during the contemporaneous period. This step also includes any emissions decreases from the project.
4. Creditable Emissions Changes - Determine which contemporaneous emissions changes are creditable.
5. Amount of the Emissions Increase and Decrease - Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.
6. PSD Review - Sum all contemporaneous and creditable increases and decreases with the emissions changes from the project to determine if a significant net emissions increase will occur.

The following table represents the calculated project emissions compared to the PSD significance levels. All emissions are in TPY. As shown in the table, all pollutants except VOC exceed the significance level.

Pollutant	Emissions	PSD Significance Level	PSD Review Required
NO_X	312.70	40	Yes
CO	240.69	100	Yes
VOC	36.89	40	No
PM_{10}	39.87	15	Yes
SO_2	272.13	40	Yes

For each pollutant that exceeded a PSD significance level, the net emissions increase is determined. The net emissions increase is the change in emissions that occurred during the contemporaneous period. The contemporaneous period begins three years prior to the start of operation. Therefore, for this project, the contemporaneous period begins November 1, 2001 and ends November 1, 2004.

Contemporaneous emissions increases and decreases are those emissions associated with new construction, a physical change, or change in the method of operation of a source that begins operation during the contemporaneous period. Contemporaneous emissions decreases are those emissions decreases associated with new construction, a physical change, change in the method of operation of a source, or reductions in actual emissions from a federally-enforceable emission limit that became effective during the contemporaneous period.

Contemporaneous emission increases and decreases were based on a review of the current Refinery permit history and future planned Refinery projects. A summary of the contemporaneous emission increases and decreases is provided in following table.

Permit Date	Permit Number	Description	Emission Increases or Decreases (TPY)			
			CO	PM_{10}	NO_X	SO_2
10/01/01	2001-173-C	No. 7 Coker Flare Gas Recovery Project	-182.48	--	-25.26	-1,168.75[A]
07/17/02	2002-138-C	Temporary Boiler Project	99.90	14.90	39.90	39.90
11/01/01 [B]	--	Naphtha In-Line Caustic Treating	0.96	2.63	11.73	20.57
12/01/01 [B]	--	Naphtha Booster Pumps	4.14	0.40	10.45	0.96
03/01/02 [B]	--	Butamer TA	3.23	0.86	13.29	0.53
04/01/02 [B]	--	No. 6 HDT Retray	0.49	0.04	0.57	0.03
01/03/02	2001-305-C	No. 3 Catalytic Reformer	14.65	5.44	-36.55	39.09
11/01/03	2001-194-C PSD	Low Sulfur Gasoline	299.11	27.43	143.88	128.1
01/01/04 [B]	--	Stripper Preheater 5FCC VRU	12.00	2.00	10.00	14.00
10/01/04	--	H-0001 Burner Replacement [C]	-28.50	--	-134.72	--
10/01/04	--	H-0015 Removal [C]	-12.81	-1.16	-15.25	-1.60
10/01/04	--	H-0048 Burner Replacement [C]	--	--	-64.60	--
8/23/01 [D]	98-169-C (M-2)	No. 5 FCCU			-0.32	
6/2/03	2002-115-C	No. 4 CTU/CVU Expansion	72.48	14.13	39.34	7.11
7/07/03	97-286-C (M-3)	No. 2 CTU Naphtha Debottlenecking Project	15.72	9.00	32.41	34.23

[A] 200 TPY of SO_2 emission decreases from this project were required by a consent decree; therefore, the emission decreases presented here are the total SO_2 decreases for the project minus 200 TPY.

[B] Estimated emissions and project timing.

[C] These units will be replaced or modified as part of this project.

[D] The recently changed NO_X Potential to Emit for No. 5 FCCU results in a NO_X emissions decrease for the netting analysis.

A contemporaneous increase or decrease is creditable only if the DEQ has not relied upon it in previously issuing a PSD permit. In addition, the PSD permit must be in effect when the increase from the proposed modification occurs. For pollutants with PSD increments, a contemporaneous increase or decrease in actual emissions which occurs before the baseline date in an area is creditable only if the increase or decrease would be considered in calculating how much of an increment remains available for the pollutant in question. A contemporaneous decrease is creditable only to the extent that it is federally enforceable from the moment that construction begins on the project with the contemporaneous emissions decrease. A source cannot take credit for a contemporaneous decrease that it has had to make, or will have to make, in order to bring an emissions unit into compliance. Furthermore, a source cannot take credit for an emission reduction from potential emissions from an emissions unit, which was permitted, but never built or operated.

As part of this project, the burners in H-0001 and H-0048 were replaced with ULNB. The decreases of NO_X and CO emissions from H-0001 are not creditable towards this project since this heater was modified as part of the Consent Decree. Also, ConocoPhillips has chosen not to take credit for the decrease of NO_X and CO emissions from H-0048. Heater H-0015 was replaced with a larger heater, H-0016. Emission decreases associated with the replacement of heater H-0015 with H-0016 can be used as creditable reductions since this unit is not part of the Consent Decree.

Several contemporaneous projects were relied upon in the issuance of Permit No. 2001-194-C PSD (Low Sulfur Gasoline Project). Emission increases and decreases from the previously relied upon contemporaneous projects are not creditable towards this project. Based on the analysis of the netting conducted for Permit No. 2001-194-C PSD, the following table includes a summary of the creditable and contemporaneous projects relied upon in the PSD netting for this project.

Permit Date	Permit Number	Description	Contemporaneous (Y/N)	Creditable (Y/N)
10/01/01	2001-173-C	No. 7 Coker Flare Gas Recovery Project	Y	Y
05/29/02[C]	2002-138-C	Temporary Boiler Project	Y	N
11/01/01[A]	--	Naphtha In-Line Caustic Treating	Y	N
12/01/01[A]	--	Naphtha Booster Pumps	Y	N
03/01/02[A]	--	Butamer TA	Y	N
04/01/02[A]	--	No. 6 HDT Retray	Y	N
01/03/02[A]	2001-305-C	No. 3 Catalytic Reformer	Y	N
11/01/03[A]	2001-194-C PSD	Low Sulfur Gasoline	Y	N
01/01/04	--	Stripper Preheater 5FCC VRU	Y	N
10/01/04[B]	--	H-0001 Burner Replacement	Y	N
10/01/04	--	H-0015 Removal	Y	Y
10/01/04[B]	--	H-0048 Burner Replacement	Y	N
8/23/2001	98-169-C(M-2)	No. 5 FCCU	Y	Y
6/2/03[A]	2002-115-C	No. 4 CTU/CVU Expansion	Y	N
7/7/03	97-286-C (M-3)	No. 2 CTU Naphtha Debottlenecking Project	Y	Y

[A] These projects were previously relied upon in Permit No. 2001-194-C PSD and are, therefore, not creditable for this project.
[B] Emission decreases from this unit are not creditable since ULNB are being installed per a Consent Decree.
[C] Emissions increases from this project are not creditable since there are no plans to build the boiler.

The following tables show a summary of the remaining creditable contemporaneous emission increases and decreases for the proposed project and the total project net emission increases as compared to the PSD significance levels. As shown, the project is subject to PSD review for PM_{10} and NO_X.

Permit Date	Permit Number	Description	Emission Increases or Decreases (TPY)			
			CO	**PM_{10}**	**NO_X**	**SO_2**
10/01/01	2001-173-C	No. 7 Coker Flare Gas Recovery Project	-182.48	--	-25.26	-1,168.75
7/7/03	97-286-C (M-3)	No. 2 CTU Naphtha Debottlenecking Project	15.72	9.00	32.41	34.23
10/01/04	--	H-0015 Removal	-12.81	-1.16	0.00[A]	-1.60
Previously Relied Upon Emissions [B]			-10.12	-3.85	-9.88	-34.80
Total			**-189.69**	**3.99**	**-2.73**	**-1,170.92**

[A] ConocoPhillips is proposing to not use the NO_X reductions associated with the removal of heater H-0015. 15.2 tpy NO_X credits are available for future use.

[B] The emissions increase for heaters H-0010 & H-6007 shown for this project were previously relied upon in permit 2001-194-C PSD, therefore, they are not included for the current project.

Pollutant	Project Related Increases (TPY)	Creditable Contemporaneous Emissions (TPY)	Net Emission Increases (TPY)	PSD Significant Emission Rate (TPY)	Subject to PSD Review?
CO	240.69	-189.69	**51.00**	100	No
PM_{10}	39.87	3.99	**43.86**	15	Yes
NO_X	312.70	-2.73	**309.97**	40	Yes
SO_2	272.13	-1170.92	**-898.79**	40	No

SECTION VI. SCOPE OF REVIEW

Since the modification will result in net emissions that exceed the significance level for PM_{10} and NO_X, the project is subject to full PSD review including Tier II public review, best available control technology (BACT), and an ambient impacts analysis.

Full PSD review is required for each pollutant that exceeds a significance level and consists of the following:

- determination of best available control technology (BACT)
- analysis of compliance with National Ambient Air Quality Standards (NAAQS)
- evaluation of existing air quality and determination of monitoring requirements
- evaluation of PSD increment consumption
- evaluation of source-related impacts on growth, soils, vegetation, visibility
- evaluation of Class I area impact

SECTION VII. PSD REVIEW

Best Available Control Technology (BACT)

A BACT analysis is required for all pollutants emitted in PSD-significant quantities. The BACT review follows the "top-down" methodology. Reviewed are the most stringent controls for each applicable pollutant based on RACT/BACT/LAER Clearinghouse (RBLC), vendor information, and available information on recently issued permits.

EPA guidance for a BACT analysis requires reviewing all possible control options starting at the top. In the course of the BACT analysis, one or more options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, or environmental impacts on a case-by-case (site specific) basis. There are essentially six steps required for a BACT review. These steps are listed below:

1. Identify All Available Control Technologies
2. Eliminate Technically Infeasible Options
3. Rank Remaining Options
4. Evaluate Remaining Options (determine most efficient based on economic analysis and energy/environmental impacts)
5. Select BACT
6. Document the Selection is BACT

A BACT analysis is only required for new or physically modified equipment that emits a pollutant that is subject to PSD review under this modification. The new/modified equipment includes heaters H-0001 and H-0016 and the fugitive components. Since the project was not significant for VOC, the fugitive components are not subject to this review. Heaters H-0001 and H-0016 are subject to this review for NO_X and PM_{10}.

BACT Analysis for Process Heater H-0001 and H-0016

NO_X

1. Identify All Available Control Technologies

The following is a list of control technologies that were identified for controlling NO_X emissions from the heater.

Control Technologies
Combined Ultra Low NO_X Burners (ULNB)/Selective Catalytic Reduction (SCR)
Ultra Low NO_X Burners (ULNB)
Selective Catalytic Reduction (SCR)
Selective Non-Catalytic Reduction (SNCR)

Low NO_X Burners with Internal Flue Gas Recirculation (IFGR)
Low NO_X Burners
Water/Steam Injection
Good Combustion Practice

2. Eliminate Technically Infeasible Options

Water/Steam Injection

The injection of steam, or water, into the combustion zone can decrease peak flame temperatures, thus reducing thermal NO_X formation. Therefore, it is important that the injected water/steam reach the primary flame zone. In order to reach the primary flame zone, the steam is injected either into the fuel, the combustion air, or directly into the combustion chamber. Water injection may be preferred over steam due to its availability, lower cost, and greater thermal effect.

Steam injection is predominately used with gas turbines. Few full-scale retrofit or test trials of steam injection on process heaters have been performed. Therefore, there is little data to document the effectiveness of water/steam injection, relative to the other technologies presented in this analysis. For these reasons, steam injection is considered technically infeasible and is eliminated from further evaluation as a potential NO_X control for the heaters.

3. Rank Remaining Options

The remaining options are ranked in the following table based on effectiveness/efficiency.

Control Technology	**U.S. EPA Listed Control Efficiency (%)[A]**	**Calculated Efficiency (%)[B]**	**Approximate Emissions (lb/MMBtu)[C]**
ULNB/SCR	92	89	0.0085
SCR	80	73	0.022
ULNB	68	56	0.035/0.060[D]
LNB		Base Case	0.08[E]
SNCR	19	--	0.087

[A] U.S. EPA "Petroleum Refinery Tier 2 BACT Analysis Final Report" Table 3-2 BACT Control Hierarchy for NO_X– Based on uncontrolled burners as the base case.

[B] Calculated efficiencies using Low NO_X Burners as the base case.

[C] U.S. EPA "Petroleum Refinery Tier 2 BACT Analysis Final Report" Table 3-2 BACT Control Hierarchy for NO_X.

[D] Heater H-0001 ULNB is only capable of 0.060 lb/MMBtu based on heater performance.

[E] Based on vendor-provided Low NO_X Burner emission factor.

4. Evaluate Remaining Options (determine most efficient based on economic analysis and energy/environmental impacts)

<u>Ultra Low NO_X Burners with Selective Catalytic Reduction</u>

The combination of ULNB with SCR has recently been used in some applications of combined cycle turbines and water tube boilers. By combining these technologies, it is possible to achieve NO_X removal efficiency of approximately 89% from a base case of LNB alone.

SCR is a post-combustion NO_X control technology. In SCR, ammonia (NH_3) diluted with air or steam is injected into the flue gas upstream of a catalytic reactor. On the catalyst surface, the NH_3 reacts with NO_X to form molecular nitrogen and water.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

The primary variable affecting NO_X reduction is temperature. There are at least two ideal SCR operating temperature ranges depending on the SCR catalyst used. The temperature range for "medium-temperature" SCR is 500 ^oF to 725 ^oF. The temperature range for "low temperature" SCR is 300 ^oF to 680 ^oF. Based on stack exit temperatures, heaters H-0001 and H-0016 would require "low-temperature" SCR catalyst.

The technical and environmental difficulties associated with SCR are as follows:

- If operating below the optimum temperature range, the catalyst activity is reduced allowing unreacted NH_3 to slip through to the exhaust. If operating above the optimum temperature range, NH_3 is oxidized, forming additional NO_X and the catalyst may suffer thermal stress damage.
- SCR systems cannot be used effectively on waste gas streams that contain significant amounts of particulate matter. Particulate deposits on the catalyst surface foul the catalyst and prohibit NO_X reduction from occurring.
- SCR systems have difficulty in dealing with sulfur, because of the potential to operate below the freezing point of ammonium bisulfate, allowing deposition on the catalyst and resulting in catalyst fouling.
- Further, environmental and safety issues exist with the on-site storage of ammonia, the occasional presence of a visible, detached plume, and disposal of the catalyst.

The cost effectiveness of a ULNB/SCR system was evaluated for the heaters based on U.S. EPA guidance and information provided by Fluor Daniels for the installation and operating costs. The baseline for the tons of NO_X controlled by the ULNB/SCR system is a low-NO_X burner (LNB) producing 0.08 lb/MMBtu NO_X. The cost to install a combined ULNB/SCR system is $10,287 per ton of NO_X controlled for heater H-0016 and $6,913 per ton of NO_X controlled for heater H-0001.

The RACT/BACT/LAER Clearinghouse (RBLC) and recently issued permits in attainment areas were reviewed for recent determinations. The reviewed determinations did not result in ULNB/SCR as BACT. Therefore, based on the costs associated with the ULNB/SCR system, the associated impacts resulting from ammonia usage/slip, and recent determinations, ULNB/SCR is eliminated from consideration.

<u>Selective Catalytic Reduction</u>

The previous section discussed SCR technology. The cost effectiveness of SCR as the sole NO_X control technology was evaluated for the heater. The costs to install an SCR system for the heaters H-0016 and H-0001 is $12,518 and $8,413 per ton NO_X controlled, respectively.

The RBLC and recently issued permits in attainment areas were reviewed for recent determinations. The reviewed determinations did not result in SCR as BACT. Therefore, based on the costs associated with the SCR system, the associated impacts resulting from ammonia usage/slip, and recent determinations, SCR is eliminated from consideration.

<u>Ultra Low NO_X Burners (ULNB)</u>

There are several designs of ultra low NO_X burners (ULNB) currently available. These burners combine two NO_X reduction steps into one burner; typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment.

In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. This design is predominately used with liquid fuels.

In staged fuel burners with IFGR, fuel pressure induces the IFGR, which creates a fuel lean zone and a reduction in oxygen partial pressure. This design is predominately used for gas fuel applications.

5. Select BACT

Since ULNB provides the highest feasible control, BACT has been proposed as ULNB at an emission rate of 0.035 lb/MMBtu for heater H-0016 and 0.06 lb/MMBtu for heater H-0001.

6. Document the Selection is BACT

The RBLC and recently issued permits in attainment areas were reviewed for recent determinations. The most stringent determinations resulted in BACT determinations requiring ULNB with emissions ranging from 0.06 lb/MMBtu to 0.030 lb/MMBtu. Therefore, the proposed control is acceptable as BACT.

PM_{10}

1. Identify All Available Control Technologies

The following is a list of control technologies that were identified for controlling PM_{10} emissions from the heater.

Control Technologies
Baghouse/Fabric Filters
Cyclone
Electrostatic Precipitator (ESP)
Wet Gas Scrubber
Good Combustion Practice

2. Eliminate Technically Infeasible Options

All the listed options are technically feasible.

3. Rank Remaining Options

Ranking of the control technologies is not needed based on the following review.

4. Evaluate Remaining Options (determine most efficient based on economic analysis and energy/environmental impacts)

While the listed control technologies are technically feasible, these types of controls are not used for controlling PM_{10} from heaters that are limited to gaseous fuels. This is based on the inherently low PM_{10} emissions associated with gaseous fuel combustion, the efficiency associated with the removal of minute particulates, and the costs for such systems.

5. Select BACT

Based on this review, BACT is proposed as limiting the process heaters to refinery fuel gas or pipeline quality natural gas, good combustion practice, and emissions of 0.0075 lb/MMBtu.

6. Document the Selection is BACT

The RBLC database lists good combustion practice as the most prevalent form of BACT for controlling PM_{10} emissions from gas-fired process heaters. Therefore, the fuel limits and good combustion practices with a limit of 0.0075 lb/MMBtu are acceptable as BACT.

Air Quality Impacts

An ambient impact analysis is required for a major modification of an existing PSD major source that results in a significant net emission increase. An impact analysis is required for each pollutant with a significant net emission increase and includes a demonstration of compliance with the Significant Impact Levels, monitoring exemption levels, National Ambient Air Quality Standards (NAAQS), and available PSD increments.

The first step in the air quality impact analyses is to determine if ambient impacts would result in a radius of impact (ROI) being defined for the facility for each pollutant based on the net emission increase. The ROI is the most distant point where approved dispersion modeling predicts a significant ambient impact will occur. A significant ambient impact occurs when modeling results in an ambient concentration above any significance impact level (SIL) as shown in the following table. If a ROI occurs for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a radius of impact, no further air quality analysis is required.

The SILs are shown in the following table.

Pollutant	Averaging Period	SIL ($\mu g/m^3$)
NO_X	annual	1
TSP/PM_{10}	annual	1
	24-hour	5
SO_2	Annual	1
	24-hour	5
	3-hour	25
CO	8-hour	500
	1-hour	2,000
O_3	*	*

* no concentration has been established. Any increase of 100 tons per year of VOC requires an ambient impact analysis.

Description of Air Quality Dispersion Model and Procedures

The dispersion model analysis for this project was conducted using the latest version (99020) of the Industrial Source Complex Short-Term Version 3 (ISCST3) model with Plume Rise Model Enhancements (ISC-PRIME) to estimate ground-level concentrations. The prime algorithms have been coupled with the regulatory ISCST3 model to form the ISC-PRIME model.

Land Use Coefficient

Based on a review of the USGS Ponca City, Oklahoma, Quadrangle 7.5 minute series topographic map and the Land Use and Land Cover map for the region immediately surrounding the Refinery, the Auer typing scheme of the land use patterns was used for this analysis. It was determined that the adjacent land use is more than 50 percent urban. Therefore, urban dispersion coefficients are used in this modeling analysis.

Terrain

The ISC PRIME model optionally calculates concentrations based on flat or elevated terrain. For this modeling analysis, elevated terrain was used. The receptor terrain elevations entered into the models are the highest elevations extracted from USGS 1:24,000 scale (7.5 minute series) digital elevation model (DEM) data of the area surrounding the Refinery. DEM is a digital file consisting of terrain elevations for ground positions at regularly spaced intervals. For each receptor, the maximum terrain elevation associated with the four DEM points surrounding the receptor is selected for the receptor elevations. DEM data was also used for the base elevations of Refinery sources and buildings.

Building Wake Effects (Downwash)

The primary improvements associated with the PRIME dispersion model are in the algorithms that predict pollutant concentrations for plumes that are affected by building downwash. Numerous comparative studies suggest that ISC-PRIME offers a considerably more accurate representation of building downwash effects. Specifically, it improves upon the downwash algorithms of the ISCST3 model in which a stack was assumed to be located centrally adjacent to the lee side of the dominant downwash structure even though the stack may actually be located upwind, downwind and up to five building heights away, and/or laterally displaced from the structure. ISC-PRIME improves upon these assumptions by having the ability to model streamlines in the downwind wake cavity and by employing an enhanced numerical simulation of the plume mass, buoyant energy, and momentum. As a result the plume is modeled throughout the cavity, near-wake, and far-wake regions, and the source-structure relationship is more accurately represented.

For the PSD modeling analysis, the direction-specific building dimensions used as input to the ISC-PRIME model were calculated using the BREEZE-AIR software. This software incorporates the algorithms of the U.S. EPA-sanctioned Building Profile Input Program (BPIP) (version 95086), which has been adopted to incorporate the PRIME downwash algorithms and released by the U.S. EPA as “BPIPPRM.” BPIPPRM is designed to incorporate the concepts and procedures expressed in the Good Engineering Practice (GEP) Technical Support document, the Building Downwash Guidance document, and other related documents, while incorporating the enhancements to improve prediction of ambient impacts in building cavities and wake regions. Comparison studies have shown that ISC-PRIME induces no biases to over- or under-predict ambient concentrations outside of the wake and cavity regions.

Meteorological Data

The ISC-PRIME air dispersion modeling was performed using 1986 through 1988 preprocessed meteorological data based on surface observations taken from Wichita, Kansas, [National Weather Service Station (NWS) station number 3928] with upper air measurements from

Oklahoma City, Oklahoma, (NWS station number 13967). The 1990 and 1991 preprocessed meteorological data are based on surface observations taken from Wichita, Kansas and upper air measurements from Norman, Oklahoma (NWS station number 3948). The anemometer height at the Wichita, Kansas, NWS station during the period of interest was 10.06 meters.

Receptor Grid

Ground-level concentrations were calculated within four Cartesian receptor grids. These four grids covered a region extending 20 km from all edges of the Refinery fenceline. The grids are defined as follows:

1. A Fenceline Grid containing 100 meter-spaced receptors along the Refinery fenceline and in areas within the ConocoPhillips fenceline that are open to the public or operated by non-ConocoPhillips employees.
2. A Fine Grid containing 100 meter-spaced receptors, extending approximately 1.0 km from the fenceline exclusive of the receptors within the Refinery fenceline.
3. A Medium Grid containing 500 meter-spaced receptors, extending 4 km beyond the Fine grid.
4. A Coarse Grid containing 1,000 meter-spaced receptors, extending approximately 15 km beyond the Medium grid.

Significant Impact Analysis

Since the netting demonstration, which was conducted in Section V, PSD Applicability, resulted in emissions above significance levels for NO_X and PM_{10}, the applicant must determine if a ROI will result due to the proposed project. The Ambient Ratio Method (A.R.M.), which assumes a default NO_2/NO_X ratio of 0.75, was used to estimate NO_2 emission rates for all sources. Except for small volume and area sources of PM_{10}, modeled input rates for each source are listed below.

Source	Description	NO_X, lb/hr	PM_{10}, lb/hr
New/Modified Sources			
H-0016	No. 1 CVU Charge Heater	3.73	0.80
H-0001	No. 1 CTU Charge Heater	0.00	0.08
Associated Sources			
H-0048	No. 2 CRU Reactor Preheater	0.00	0.42
H-0005	No. 1 CTU Crude Charge Heater	3.40	0.30
H-0028/H-0029	No. 7 Coker Process Heaters	8.80	0.65
H-0023	FCCU Gas Oil Hydrotreater Heater	4.84	0.21
H-0047	Gas Oil HDT Reactor Feed Heater	1.01	0.13
H-7501	No. 6 HDT Reactor Charge Heater	2.29	0.16
H-0046	No. 2 CRU Charge Heater	2.47	0.28
H-6007	No. 3 CRU Reactor Preheater	13.05	0.71
H-6012	No. 3 CRU Desulfurization Preheater	0.63	0.08

Source	Description	NO_X, lb/hr	PM_{10}, lb/hr
H-6013	CTU Crude Charge Process Heater	0.97	0.29
H-0010	Sat Gas Plant Naphtha Reboiler	2.84	0.22
H-0011	No. 7 HDS Charge Heater	0.55	0.03
H-0057/H-0058/ H-0059	Alky Depropanizer Heaters	5.42	0.91
H-5001	No. 5 FCC Preheater	17.44	0.49
#5 FCCU	No. 5 FCC Regenerator	0.44	2.98
COG-1DB	No. 1 Cogeneration Unit Duct Burner	1.75	0.17
COG-2DB	No. 2 Cogeneration Unit Duct Burner	1.75	0.17
Alky Flare	Alky Flare	-5.77	0.00
Coke Pad	Coke Pad	0.00	0.07
Coker Crusher	Coker Crusher	0.00	0.01
CT-10	Y-7 Cooling Tower-Cell 1	0.00	0.0006
CT-10	Y-7 Cooling Tower-Cell 2	0.00	0.0006
CT-10	Y-7 Cooling Tower-Cell 3	0.00	0.0006
CT-10	Y-7 Cooling Tower-Cell 4	0.00	0.0006

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	Modeled Impacts ($\mu g/m^3$)
NO_2	Annual	1	2.62
PM_{10}	24-hour	5	2.81
	Annual	1	0.71

The modeling indicates facility emissions will result in ambient concentrations above the significance impact levels for NO_2. Therefore, full impact modeling is required for this pollutant.

Ambient Monitoring

The maximum ground-level concentrations of pollutants, predicted by air dispersion modeling, has demonstrated that the significant net emission increase from the project will result in ambient impacts below the monitoring exemption levels for NO_2 and PM_{10}. Therefore, no pre-construction or post-construction ambient monitoring will be required. The maximum ambient impacts of the source and the monitoring exemption levels are shown in the following table. However, an existing NO_2 monitor is located in the Ponca City area and has been used for pre-construction monitoring.

Pollutant	Monitoring Exemption Levels		Ambient Impacts
	Averaging Time	$\mu g/m^3$	$\mu g/m^3$
NO_2	Annual	14	2.62
PM_{10}	24-hour	10	2.81

Full Impact Analysis

A Full Impact Analysis is required to be conducted when the net emissions increase from the proposed project results in ambient impacts above any SIL or VOC emissions exceed 100 TPY. Ambient impacts above the SILs resulted for NO_2. Therefore, a full impact analysis is required for NO_2. A full impact analysis consists of a NAAQS analysis and PSD Increment analysis.

NAAQS Analysis

To demonstrate compliance with the NAAQS, the impact of emissions from the sources at the Refinery and inventory sources were modeled and added to background concentrations.

The full impact analysis to demonstrate compliance with the NAAQS requires modeling the sources at the refinery (including the proposed increases) and existing sources as well as new significant sources. To determine which of the existing sources as well as new significant sources to include in the NAAQS review, the radius of impact is determined (ROI). The ROI is defined as the area circumscribed by a radius extending to the farthest receptor that exceeds the significance impact level for each pollutant and averaging period. All sources within the ROI plus 50 kilometers have the potential to significantly contribute to ambient impacts and are included.

For the NO_2 annual averaging period, it was determined that the ROI extends for a distance of 2.47 km from the center of the Refinery.

In order to eliminate sources with minimal affect on ambient impacts, a screening procedure known as the “20D Rule” was applied to the sources on the emission inventory from Oklahoma. This is a screening procedure designed to reduce the number of insignificant sources. The rule is applied by multiplying the distance from the sources (in kilometers) by 20. If the result is greater than the emission rate (in tons per year), the source is eliminated. If the result is less than the emission rate, the source is included in the NAAQS analysis. After refinery sources and all sources not eliminated by the 20D rule are modeled, the results are added to background concentrations for a determination of compliance.

An acceptable monitor for NO_2 is located in the Ponca City Area. The most recent complete year of data was obtained from the U.S. EPA AIRSWEB database and used to determine the background concentration for NO_2. The highest NO_2 concentration was used for the annual averaging period.

Pollutant	Annual ppm (ug/m^3) [a]
NO_2 [b]	0.0064 (12.2)

a. All values are monitored values from 2002
b. Data from tribal monitor ID 400719003-1

As stated, the NAAQS analysis includes modeling existing and new refinery sources plus any sources within 50 kilometers of the ROI unless excluded under the 20D method. Due to the number of sources included in this list, the specific emissions rates and stack parameters are not identified here; however, the sources are listed. The additional data is identified and available in the permit application. In addition, the emission methodologies used for each source is described following.

Facility	UTM Easting	UTM Northing
Jupiter Sulphur, LLC	671,681	4,060,547
Continental Carbon Company	672,497	4,059,349
OMPA	670,981	4,065,562
OG&E, Sooner Station	674,604	4,035,902
OG&E, Ponca City Turbines	670,948	4,061,666

All Refinery sources were modeled at their permit allowable or maximum design rate for the NAAQS Analysis.

The cogeneration facility at the Refinery was installed as a joint venture between Oklahoma Gas and Electric (OG&E) and ConocoPhillips. The cogeneration facility consists of two combustion turbines and two Heat Recovery Steam Generators (HRSGs), each equipped with duct burners. The combustion turbines are owned and operated by OG&E, while the duct burners (DB-01, and DB-02) are owned and operated by ConocoPhillips. Boilers B-6 and B-7, which are owned and operated by ConocoPhillips, normally generate small quantities of steam for the Refinery; however, these boilers can be utilized at their full capacity when the combustion turbines are not operational. The emissions from the duct burners and the boilers are capped at 930.2 TPY NO_X and 1,602.3 TPY SO_2.

For the annual averaging periods, the worst-case stack was determined by modeling a unit emission rate through boilers and the duct burners. Emissions for the cap were allocated to the worst-case stack and then to the next worst-case, until the cap was consumed.

The Research and Development facility is permitted separately as a “synthetic minor” source since it is classified under SIC code 8731. The pilot plant boilers, heaters, and flare are permitted with the flexibility to operate under an emissions cap. The emissions cap proposes to limit emissions from the pilot plant to 96 tons per year (TPY) for all criteria pollutants. The pilot plant was conservatively assumed to have all units, except the flare, operating simultaneously.

The emission sources associated with the Cevolution (Carbon Fibers) facility were not included in the analysis because these sources are no longer in operation and there are no plans to resume operation.

The list of sources within the ROI plus 50 km and not eliminated by the Louisiana 20-D rule were modeled at their permitted emission limit. Source parameters not included in permits or permit memoranda were obtained from the 2000 EI.

Shown in the following table is the maximum concentration from all receptors. Since this is below the NAAQS, the facility is in compliance.

NAAQS Analysis Results				
Pollutant	**Refined Model Maximum**	**Monitored Background**	**Refined + Background**	**NAAQS Limit**
	(μg/m^3)	**(μg/m^3)**	**(μg/m^3)**	**(μg/m^3)**
NO_2, annual	66.34	15.05	81.39	100

PSD Increment Analysis

The PSD Increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging times) and is the ambient concentration existing at the time that the first complete PSD permit is submitted for that area. PSD increment consumers are defined as (1) new major stationary sources that have been constructed since, or existing major stationary sources that have been modified, after the major source baseline date, and (2) new stationary sources that have been constructed, or existing stationary sources that have been modified, after the minor source baseline date. An emission source removed from the area is considered as a reduction in consumed increment.

The baseline date was determined to be February 20, 1992, for NO_2. The following table lists the NO_2 increment.

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

The first step in evaluating increment consumption is to develop a list of sources within the ROI plus 50 km. These sources were then screened using the previously described 20-D rule. Those sources not screened out were then reviewed to determine dates of installation. Those units installed after the baseline dates were included in the modeling and were modeled at their full potentials for the PSD Increment Analysis. The full potential used was the permitted emission limit. Following is a description of the emission rates used for all refinery sources. For all sources with emissions listed as NO_X, the Ambient Ratio Method was used to calculate the NO_2 emissions.

All Refinery sources installed since the baseline date of February 20, 1992, for NO_2 were modeled at their full potentials. The full potential is either the permitted emission limits or for those units that have not been permitted, the maximum design potential of the unit. All units installed prior to the baseline dates were adjusted to account for their current increment consumption. The sources' past actual emissions (i.e., emissions prior to the baseline date) were subtracted from current potentials to obtain the annual emission rate. All units removed from operation since the baseline dates were modeled as negative emission rates based on their actual emissions prior to the baseline date.

The following units required special consideration as described following.

Heater H-6007

The stack height for H-6007 increased from 57 feet to 120 feet in 1992. All other stack parameters remained the same. Therefore, both the pre-baseline and the current conditions were modeled. The pre-baseline situation was modeled with a negative emission rate and the current configuration was modeled with a positive value.

Refinery Cogeneration Plant

To determine pre-baseline values a ratio of the amount of barrels refined in 2000 to the amount refined in 1991 was used. This amount was then subtracted from the current permit limit and conservatively split among the units from worst case to best-case stack. All the increment was consumed by DB-01.

Refinery Flares

Emissions from increment consuming flares were assumed to only come from the flare pilot fuel, since the flares are only used in upset conditions.

Refinery Research and Development Plant

The facility was conservatively assumed to be an increment consumer with no adjustment made for its emissions prior to baseline dates.

The following modeling results demonstrate that the proposed project will not result in a violation of the PSD Increment.

Pollutant	Averaging Period	Increment	Maximum Modeled NO_2 Increase
NO_2	Annual	25 $\mu g/m^3$	17.29 $\mu g/m^3$

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 for NO_X. The following was addressed as required:

- A growth impact analysis
- Soils and vegetation impact analysis
- A visibility impairment impact analysis

Growth Impacts

The elements of a growth impact analysis include a projection of the associated industrial, commercial, and residential growth that will occur in the area due to the project, including the potential impact upon ambient air due to this growth. No secondary or auxiliary industrial growth will occur as a result of the proposed project. Since there is no significant associated commercial or industrial growth as a result of the proposed project, negligible growth-related air pollution impacts are expected.

Soils and Vegetation

The following discussion will review the project's potential to impact its agricultural surroundings based on the project's allowable emission rates and resulting ground level concentrations of NO_X. NO_X was selected for review since it has been shown to be capable of causing damage to vegetation at elevated ambient concentrations.

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. The gaseous pollutant acting directly on the organism causes acute and chronic effects, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

NO_2 may affect vegetation either by direct contact of NO_2 with the leaf surface or by solution in water drops, becoming nitric acid. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. The maximum predicted NO_2 pollutant concentration from the proposed project is below the secondary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated due to the proposed project.

Visibility Impairment

The project is not expected to produce any perceptible visibility impacts in the immediate vicinity of the Ponca City Refinery. Given the limitation of 20% opacity of emissions, and a reasonable expectation that normal operation of the units will result in 0% opacity, no immediate visibility impairment is anticipated.

Class I Area Impact Analysis

One of the purposes of the PSD program is "to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value."

Under the PSD provisions, Congress established a land classification scheme for those areas of the country with air quality better than the NAAQS. Class I allows very little deterioration of air quality, Class II allows moderate deterioration, and Class III allows more deterioration, but in all cases, the pollution concentrations should not violate any of the NAAQS. Certain existing areas were designated as mandatory Class I, which precludes re-designation to a less restrictive class, in order to acknowledge the value of maintaining these areas in relatively pristine condition. These Class I areas include:

1. International Parks
2. National Wilderness Areas and National Memorial Parks in excess of 5,000 acres
3. National Parks in excess of 6,000 acres

The nearest mandatory Class I area is the 59,020 acre Wichita Mountains National Wildlife Refuge (WMNWR) located approximately 243 km to the southwest of the Ponca City Refinery. A Class I area impact analysis is not required since this area is located more than 200 km from the facility.

SECTION VIII. OKLAHOMA AIR POLLUTION CONTROL RULES

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

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. A demonstration of compliance with Air Quality Standards and Increments was conducted in Section VII, "PSD Review."

OAC 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2005, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Cb, Subpart Cc, Subpart Cd, Subpart AAA, Subpart BBBB, Subpart DDDD, Subpart HHHH, and Appendix G. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-5 (Registration, Emission Inventory and Annual Operating Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division (AQD). Emission inventories have been submitted and fees paid for previous years as required.

OAC 252:100-7 (Permits for Minor Facilities) [Not Applicable]
This refinery is a major source because the total facility emissions are greater than 100 TPY of any regulated pollutant. An application for a modification to a major (Part 70) source requires processing under Subchapter 8.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 3 summarizes permit application fees for Part 70 source permits. ConocoPhillips has submitted the required construction permit application fee of $1,500.
Part 5 includes the general administrative requirements for Part 70 permits. A construction permit is required for any physical change that would be a significant modification under 252:100-8-7.2(b). Such changes include projects that cannot be defined as “Insignificant Activities” or “Trivial Activities,” and are not authorized in a current state permit. Insignificant activities mean individual emission units, to which a state or federal requirement does not apply, that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following:

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

This proposed project is considered a physical change that is considered a significant modification of a Part 70 permit; therefore, a construction permit is required. After construction, the operating permit for this modification will be incorporated into the facility’s initial Part 70 permit that is yet to be issued.
Part 7 summarizes Prevention of Significant Deterioration (PSD) requirements. See the “Federal Regulations” section for a discussion of PSD regulations.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Part 70/Title V sources must report any exceedance that poses an imminent and substantial danger to public health, safety, or the environment as soon as is practicable. Under no circumstances shall notification be more than 24 hours after the exceedance.

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

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Subchapter 19 specifies PM emissions limitations for process equipment and fuel-burning equipment. The most stringent fuel-burning equipment limitation is 0.10 lb/MMBtu. Based on AP-42 (7/98), Table 1.4-2 factors for gas fuel, PM emissions from the fuel-burning equipment will be 0.0076 lb/MMBtu. The permit will require that the fuel-burning equipment be fired with gaseous fuel to ensure compliance with this subchapter.

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

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions 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. This project does not involve any new sources with significant fugitive dust emissions.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). This part prohibits discharge of SO_2 from new gas-fired fuel-burning equipment in excess of 0.2-lb/MMBtu three-hour average. The proposed new source and the additional heaters to be included in this permit are subject to NSPS Subpart J, which limits the hydrogen sulfide content and result in emissions of 0.0385/0.0407 lb/MMBtu. Therefore, the sources will be in compliance.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
Subchapter 33 affects discharge of NO_X from new gas-fired fuel-burning equipment with a rated heat input of 50 MMBtu/hr or more. NO_X is limited to 0.2-lb/MMBtu, three-hour average, expressed as NO_2. Process heater H-0016 will be limited to NO_X emissions of 0.035 lb/MMBtu. Process heater H-0001 will be limited to NO_X emissions of 0.060 lb/MMBtu. Process heater H-0048 will be limited to NO_X emissions of 0.07 lb/MMBtu. These emission rates are in compliance with this subchapter.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
The project does not involve the installation of any of the following equipment: 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 12/28/74 with a capacity of 40,000 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with internal/external floating roofs or vapor recovery devices. There are no new or modified tanks as a result of this project.
Part 7 also requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. All the combustion units are subject to this requirement.
Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. The new pumps and compressors will be subject to this requirement.

OAC 252:100-41 (Hazardous Air Pollutants (HAP)) [Applicable]
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on September 1, 2005, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, YYYY, ZZZZ, AAAAA, BBBBB, CCCCC, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS and TTTTT are hereby adopted by reference as they exist on September 1, 2005. These standards apply to both existing and new sources of HAPs. These requirements are covered in the "Federal Regulations" section.
Part 5 was a **state-only** requirement governing sources of toxic air contaminants that have emissions exceeding a *de minimis* level. However, Part 5 of Subchapter 41 has been superseded by OAC 252:100-42, effective June 15, 2006.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Part 5 of OAC 252:100-41 was superceded by this subchapter. Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. 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 (Sampling and Testing Methods) [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.

SECTION IX. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
PSD applies to this project. PSD review was completed in Section VII.

NSPS, 40 CFR Part 60 [Subparts A, J, and GGG are Applicable]
Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected sources. Within 30 days after starting construction of the affected sources, ConocoPhillips must notify DEQ that construction has commenced. A notification of the actual date of initial startup of any affected source will be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup of the source. ConocoPhillips must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ. The permittee will comply with the notification requirements set forth in Subpart A.

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam-generating units with a design capacity greater than 100 MMBtu/hr heat input and which commenced construction or modification after June 19, 1984. H-0001 and H-0048 have design capacities above 100 MMBtu/hr; however, they are defined as process heaters and are, therefore, not subject.

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects industrial-commercial-institutional steam generating units with a design capacity between 10 and 100 MMBtu/hr heat input and which commenced construction or modification after June 9, 1989. Heater H-0016 will have a design capacity between 10 and 100 MMBtu/hr; however, this heater is defined as a process heater and is, therefore, not subject.

Subpart J, Petroleum Refineries. This subpart provides a limit of 0.10 gr/dscf for H_2S content in fuel gas burned in any fuel gas combustion device. A continuous monitoring device to measure either SO_2 emission concentration or H_2S concentration in the fuel gas must also be installed. Subpart J also includes testing, reporting, and recordkeeping requirements. The heater H-0016 to be installed as part of this project will be subject to Subpart J and will comply with the H_2S requirements of Subpart J. In addition, heaters H-0001 and H-0048 will be included in this permit and are subject to the H_2S requirements of this subpart.

Subpart GGG, Equipment Leaks of VOC in Petroleum Refineries. Subpart GGG affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service which commenced construction or modification after January 4, 1984, and which is located within a process unit in a petroleum refinery. The subpart defines “process unit” as “components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.” The new equipment is required to only comply with 40 CFR Part 63, Subpart CC. If any of the equipment is determined to contain less than 5% HAP, it is subject to this subpart only.

Subpart QQQ, This subpart affects refinery wastewater systems for which construction, reconstruction, or modification commenced after May 4, 1987. This project will involve the installation of 3 controlled drains; however, two uncontrolled drains will be removed which will result in a decrease in emissions of the individual drain system. Therefore, this change is not subject to this subpart.

NESHAP, 40 CFR Part 61 [Not Applicable]
Subpart J, Equipment Leaks of Benzene. This subpart applies to pumps, compressors, pressure relief devices, sampling connections, systems, open-ended valves or lines, valves, flanges and other connectors, product accumulator vessels, and control devices or systems. The benzene concentration for each affected unit will be less than 10% by weight. Therefore, in accordance with 40 CFR 61.110(c)(3), the control requirements in this subpart are not applicable to this proposed project.

Subpart FF, Benzene Waste Operations. This subpart applies to waste streams at chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries that have benzene-containing hazardous waste treatment, storage, and disposal facilities. There are no emissions of any regulated pollutant: asbestos, mercury, benzene (except for trace amounts in streams containing less than 1% by weight benzene), vinyl chloride, radionuclides, arsenic, beryllium, or coke oven emissions. The proposed equipment is not subject to this subpart.

NESHAP, 40 CFR Part 63 [Subparts CC and DDDDD are Applicable]
Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. This subpart affects petroleum refining process units, and related emission points, located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act and emits or contacts one or more of the hazardous air pollutants listed in table 1 of this subpart. The various emission units include:

- miscellaneous process vents
- storage vessels
- wastewater streams and treatment operations
- equipment leaks
- gasoline loading racks
- marine vessel loading operations

This project involves the construction of equipment leak components. The equipment leak components are only required to comply with this subpart.

Subpart DDDDD, Industrial/Commercial/Institutional Boilers and Process Heaters. This subpart affects new, reconstructed, and existing boilers and process heaters fired with solid, liquid, and gaseous fuels. New process heater H-0016, which is included in this project, is a large unit, defined as watertube boilers and process heaters with heat input capacities greater than 10 million British thermal units per hour (MMBtu/hr). H-0016 will be fired with natural gas or refinery fuel gas. Therefore, H-0016 must meet the CO concentration standard of 400 ppmdv corrected to 3% oxygen. H-0016 has a heat input capacity greater than 100 MMBtu/hr and is required to use a CO continuous emission monitor system (CEMS) to demonstrate that average CO emissions, on a 30-day rolling average, are equal to or less than the CO standard. The permittee will also be required to meet the testing, monitoring, and recordkeeping requirements of this subpart. None of the modified process heaters included in this project, H-0001 and H-0048, will be reconstructed as that term is defined in paragraph §63.7490 and, therefore, are only subject to the initial notification requirements of this subpart.

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

- It is subject to an emission limit or standard for an applicable regulated air pollutant.
- It uses a control device to achieve compliance with the applicable emission limit or standard.
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY.

The proposed new equipment is not subject to CAM since emissions are controlled through the use of inherent or passive control measures.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
This project will not require storage of any regulated substance above the applicable threshold limits (Section 112r of the Clean Air Act 1990 Amendments). However, a Risk Management Plan had to be submitted to EPA Region 6 by June 21, 1999, for the entire facility. ConocoPhillips submitted a plan, No. 22480, on January 22, 2001. More information on this federal program is available on the web page: *www.epa.gov/ceppo*

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

Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

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

SECTION X. COMPLIANCE

A. Original Permit

Tier Classification and Public Review

The application was determined to be Tier II based on the request for a construction permit for a Part 70 source for a facility change that is considered a significant modification as defined in OAC 252:100-8-7.2(b)(2)(A).

The applicant 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 real property.

The applicant published the "Notice of Filing a Tier II Application" in the *Ponca City News*, a daily newspaper in Kay County, on November 7, 2002. The application was made available for public review at the Ponca City Library and at the AQD office. The applicant published the "Notice of Draft Permit and Public Meeting" in the *Ponca City News*, a daily newspaper in Kay County, on January 26, 2004. The notice stated that the draft permit was available for public review at the Ponca City Library or at the AQD office and that a public meeting would be held on March 2, 2004. This facility is also located within 50 miles of the Oklahoma border with Kansas. The state of Kansas was notified of the draft permit. The public meeting was held as scheduled. No comments were received from the public, the EPA, or the state of Kansas. Information on all permit actions is available for review on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*.

Fees Paid

A major source construction permit fee of $1,500 was paid.

B. Modification M-1

Tier Classification and Public Review

Since the BACT determination was modified from the original application, this application was determined to be Tier II based on the request for a modification of a construction permit for a Part 70 source for a change that is considered a significant modification as defined in OAC 252:100-8-7.2(b)(2)(A).

The applicant 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 real property.

The applicant published the "Notice of Filing a Tier II Application" in the *Ponca City News*, a daily newspaper in Kay County, on March 29, 2005. The application was made available for public review at the Ponca City Library and at the AQD office. The applicant also published a "DEQ Notice of Draft Permit and Public Meeting" in the *Ponca City News*, on May 1, 2005. A public meeting for public comments on the draft permit was held on June 2, 2005 at the Pioneer Technology Center in Ponca City. No comments were received during the public comment period and no one from the public, other than employees of the applicant, attended the public meeting and no comments were made. This facility is located within 50 miles of the Oklahoma border with Kansas and the state of Kansas was notified of the draft permit. No comments were received from the state of Kansas. The applicant requested that EPA review be concurrent with public review. A copy of the draft permit was sent to EPA Region VI for a 45-day review period on April 27, 2005. No comments were received from EPA.

Fees Paid

A modification to a major source construction permit fee of $1,500 was paid.

C. Modification M-2

Tier Classification and Public Review

This application has been determined to be Tier I, therefore, no public review is required. A copy of the "proposed" permit was sent to EPA Region VI for a 45-day review period. No comments were received from the EPA.

Fees Paid

A modification to a major source construction permit fee of $1,500 was paid.

SECTION XI. SUMMARY

The applicant has demonstrated the ability to achieve compliance with the applicable air quality rules and regulations. Ambient air quality standards are not threatened at the site. There are no active Air Quality compliance or enforcement actions that would prevent issuance of this permit. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

ConocoPhillips
Ponca City Refinery
No. 1 Crude Topping Unit Upgrade **Permit No. 2002-476-C (M-2) PSD**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on October 29, 2002, and with supplemental information submitted on March 14, 2005, and March 7, 2006 and June 29, 2006. The Evaluation Memorandum dated September 18, 2006, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and emissions limitations

A. Heaters

Emission Unit	Pollutant	Emissions	
		lb/hr*	TPY
H-0016, No. 1 CVU Charge Heater	CO	4.27	18.69
	PM_{10}	0.80	3.48
	NO_X	3.73	16.36
	SO_2	4.10	17.95
	VOC	0.58	2.52

* 365-day rolling average

i. The permittee shall monitor/record the fuel gas Btu content, at least once weekly. [OAC 252:100-8-6(a)]

ii. The permittee shall monitor/record the fuel gas usage, daily. [OAC 252:100-8-6(a)]

iii. The heater shall be constructed with Ultra Low NO_X Burners with NO_X emissions limited to 0.035 lb/MMBtu. [40 CFR 52]

iv. The heater shall be operated using good combustion practices to comply with the listed emission rates. [OAC 252:100-37]

v. Compliance with the NO_X and CO annual limits shall be determined daily and be based on compliance with the 365-day rolling average lb/hr emission rates as listed. The 365-day rolling average lb/hr emission rates shall be based on the daily fuel gas usage, weekly fuel gas Btu content, and heater specific emission factors.
[OAC 252:100-8-6(a)]

vi. H-0016 is subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements, including but not limited to: [40 CFR 60, Subpart J]

a. §60.104 Standards for sulfur oxides. The heater shall combust only pipeline grade natural gas or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.10 gr/dscf (160 ppmv @ 60^oF).
b. §60.105 Monitoring of emissions and operations.
c. §60.106 Test methods and procedures.
d. §60.107 Reporting and recordkeeping requirements.
e. §60.108 Performance test and compliance provisions.

vii. H-0016 is subject to NESHAP 40 CFR Part 63, Subpart DDDDD and shall comply with all applicable requirements and standards including, but not limited to: [40 CFR Part 63, Subpart DDDDD]

a. §63.7499-§63.7500 Emission Limits and Work Practice Standards. Emissions of CO from the heater shall be within a CO concentration limit of 400 ppm by volume on a dry basis corrected to 3% oxygen. Compliance with the CO emission standard will be based on a 30-day rolling average.
b. §63.7535-§63.7541 Continuous Compliance. The permittee shall install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide on the exhaust stack(s) of the heater.
c. §63.7545-§63.7560 Notifications, Reports, and Records.

viii. At such times as directed by Air Quality, the permittee shall conduct performance testing and furnish a written report to Air Quality documenting compliance with emissions limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR Part 60: [OAC 252:100-43]

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 7E: Determination of Nitrogen Oxide Emissions from Stationary Sources.
Method 10: Determination of Carbon Monoxide Emissions from Stationary Sources.

NO_X and CO testing shall be conducted while the unit is operating within 10% of the maximum firing rates.

Emission Unit	Maximum Firing Rate, MMBtu/hr*	Pollutant	Emissions	
			lb/hr*	TPY
H-0001, No. 1 CTU Charge Heater	175	CO	7.00	30.66
		PM_{10}	1.31	5.75
		NO_X	10.60	46.00
		SO_2	6.72	29.43
		VOC	0.95	4.14

* 365-day rolling averages

i. NO_X emissions shall not exceed 0.20 lb/MMBtu, 3-hour average.
[OAC 252:100-33]

ii. The heater shall be constructed with Ultra Low NO_X Burners with NO_X emissions limited to 0.060 lb/MMBtu, 365-day rolling average. [Civil Action H-01-4430]

iii. CO emissions shall be limited to 0.04 lb/MMBtu on a 365-day rolling average basis and 0.06 lb/MMBtu on a 24-hour rolling average basis except during periods when the heater is firing at a rate that is less than 30% of the heater's maximum firing rate in MMBtu/hr when CO emissions shall be limited to 0.08 lb/MMBtu on a 7-day rolling average basis. CO emissions during periods of startup, shutdown, or malfunctions will not be used for determining compliance with the 24-hour or 7-day rolling average basis limits, provided the permittee implements good air control practices to minimize emissions during such periods.
[Civil Action H-01-4430]

iv. The heater shall be operated using good combustion practices to comply with the listed emission rates. [OAC 252:100-37]

v. Upon installation of the Ultra Low NO_X Burner technology, Continuous Emission Monitors for NO_X and CO shall be installed on heater H-1 to monitor emissions of NO_X and CO. [Civil Action H-01-4430]

vi. Within 180 days of commencement of operation of the Ultra Low NO_X Burners, ConocoPhillips shall certify, calibrate, maintain, and operate NO_X and CO CEMs in accordance with the requirements of 40 C.F.R. §§ 60.11, 60.13, and Part 60 Appendix A, B, and F. With respect to 40 C.F.R. Part 60, Appendix F, in lieu of the requirements of 40 C.F.R. Appendix F §§ 5.1.1, 5.1.3, and 5.1.4, ConocoPhillips shall conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) once every twelve calendar quarters, provided that a cylinder gas audit is conducted each calendar quarter.
[Civil Action H-01-4430]

vii. Compliance with the NO_X and CO annual limits shall be determined daily and be based on 365-day rolling average lb/hr emission rates as determined by CEM data. [OAC 252:100-8-6(a)]

viii. H-0001 is subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements, including but not limited to: [40 CFR 60, Subpart J]

a. §60.104 Standards for sulfur oxides. The heater shall combust only pipeline grade natural gas or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.10 gr/dscf (160 ppmv @ 60°F).
b. §60.105 Monitoring of emissions and operations.
c. §60.106 Test methods and procedures.
d. §60.107 Reporting and recordkeeping requirements.
e. §60.108 Performance test and compliance provisions.

Emission Unit	Maximum Firing Rate, MMBtu/hr*	Pollutant	Emissions	
			lb/hr*	TPY
H-0048, No. 2 CRU Reactor Preheater	241.4	CO	9.70	42.3
		PM_{10}	1.80	7.88
		NO_X	16.90	74.01
		SO_2	9.27	43.35
		VOC	1.30	5.70

* 365-day rolling average

i. NO_X emissions shall not exceed 0.20 lb/MMBtu, 3-hour average. [OAC 252:100-33]

ii. NO_X emissions shall be limited to 0.07 lb/MMBtu on a 365-day rolling average basis. [Civil Action H-01-4430]

iii. The heater shall be operated using good combustion practices to comply with the listed emission rates. [OAC 252:100-37]

iv. Upon installation of Ultra Low NO_X Burner technology, Continuous Emission Monitors for NO_X and CO shall be installed on heater H-0048 to monitor emissions of NO_X and CO. [OAC 252:100-8-6(a)]

v. Within 180 days of commencement of operation of Ultra Low NO_X Burners, ConocoPhillips shall certify, calibrate, maintain, and operate NO_X and CO CEMs in accordance with the requirements of 40 C.F.R. §§ 60.11, 60.13, and Part 60 Appendix A, B, and F. With respect to 40 C.F.R. Part 60, Appendix F, in lieu of the requirements of 40 C.F.R. Appendix F §§ 5.1.1, 5.1.3, and 5.1.4, ConocoPhillips shall conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) once every twelve calendar quarters, provided that a cylinder gas audit is conducted each calendar quarter. [OAC 252:100-8-6(a)]

vi. Compliance with the NO_X and CO annual limits shall be determined daily and be based on 365-day rolling average lb/hr emission rates as determined by CEM data.
[OAC 252:100-8-6(a)]

vii. H-0048 is subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements, including but not limited to: [40 CFR 60, Subpart J]

a. §60.104 Standards for sulfur oxides. The heaters shall combust only pipeline grade natural gas or refinery fuel gas with a 3-hour rolling average maximum H_2S concentration of 0.10 gr/dscf (160 ppmv @ 60°F).
b. §60.105 Monitoring of emissions and operations.
c. §60.106 Test methods and procedures.
d. §60.107 Reporting and recordkeeping requirements.
e. §60.108 Performance test and compliance provisions.

viii. CO emissions shall be limited to 0.04 lb/MMBtu on a 365-day rolling average basis and 0.06 lb/MMBtu on a 24-hour rolling average basis except during periods when the heater is firing at a rate that is less than 30% of the heater's maximum firing rate in MMBtu/hr when CO emissions shall be limited to 0.08 lb/MMBtu on a 7-day rolling average basis, or during periods of catalyst regeneration when CO emissions shall be limited to 400 ppmvd @ 3% O_2 on a 7-day rolling average basis. CO emissions during periods of startup, shutdown, or malfunctions will not be used for determining compliance with the 24-hour or 7-day rolling average basis limits, provided the permittee implements good air control practices to minimize emissions during such periods. [Civil Action H-01-4430]

B. Fugitive Components

Fugitive Components, FUG	Number*
GGG Components Added	
Gas Valves	224
Light Liquid Valves	96
Heavy Liquid Valves	420
Flanges	2664
Light Liquid Pumps	1
Heavy Liquid Pumps	4
Gas Relief Valves to Flare	1
QQQ Components Added	
Controlled Process Drains	3

* Equipment counts and emissions from equipment leaks associated with this project are estimates only and are included in this permit solely for the purposes of documenting regulatory applicability for this project. The exact counts and emissions are not to be construed as operating limitations. The applicable requirements associated with fugitive emissions from equipment leaks are set forth in the equipment leak detection and repair program as specified in the following permit conditions.

i. NESHAP, 40 CFR Part 63, Subpart CC, applies to the following affected equipment: each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]

a. §63.642 General Standards
b. §63.648 Equipment Leak Standards
c. §63.654 Reporting and Recordkeeping Requirements

ii. Equipment determined not to be in HAP service (<5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.

2. Upon issuance of an operating permit, the permittee shall be authorized to operate the listed equipment, continuously (24 hours per day, every day of the year). [OAC 252:100-8]

3. The permittee shall update the Title V application within 180 days of start-up to incorporate the requirements of this permit. [OAC 252:100-8]

4. The permittee shall keep records of compliance as specified in S.C. #1. These records shall be made available to regulatory personnel upon request. Required records shall be retained on location for a period of at least five years following dates of recording. [OAC 252:100-43]

5. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility.

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

a. OAC 252:100-7 Permits for Minor Facilities.
b. OAC 252:100-11 Alternative Emissions Reduction.
c. OAC 252:100-15 Mobile Sources.
d. OAC 252:100-39 Nonattainment Areas.

6. No later than 30 days after each anniversary of the issuance date of the Part 70 operating permit for this facility, 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 the Part 70 operating permit. The following specific information will be required to be submitted:

[OAC 252:100-8-6 (c)(5)(A)(C) & (D)]

a. Daily results of the 365-day averages for NO_X and CO emissions from H-0001, H-0016, and H-0048.
b. Summary of all emissions testing results.

7. Upon completion of construction, heater H-0015 shall be removed from service. [40 CFR 52]

8. Upon commencing construction, all permit conditions referring to H-0048 in Permit Numbers 2000-206-C (M-1) and 91-043-O (M-4) are considered null and void.

9. Upon commencing construction, all permit conditions referring to H-0001 in Permit Number 2001-311-C are considered null and void.

10. This permit supercedes Permit Number 2002-476-C (M-1) PSD, which is now null and void.

ConocoPhillips
Dave Gamble
P.O. Box 1267
1228RB
Ponca City, OK 74602-1267

Re: Permit Number 2002-476-C (M-2) PSD
No. 1 Crude Topping Unit Upgrade

Dear Mr. Gamble:

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

Thank you for your cooperation in this matter. If I may be of further service, please contact me at (405) 702-4200.

Sincerely,

Grover R. Campbell, P.E.
Existing Source Permit Section
AIR QUALITY DIVISION

cc: Kay County

PART 70 PERMIT

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

Permit No. 2002-476-C (M-2) PSD

ConocoPhillips,

having complied with the requirements of the law, is hereby granted permission to construct the specified equipment for the No. 1 Crude Topping Unit Upgrade in Ponca City, Kay County, Oklahoma,

subject to the following conditions attached:

[x] Standard Conditions dated July 1, 2005

[x] Specific Conditions

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

______________________________ ____________________

Chief Engineer, Air Quality Division **Date**

DEQ Form #100-890 Revised 2/14/05

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT STANDARD CONDITIONS (July 1, 2005)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with Title V of the federal Clean Air Act (42 U.S.C. 7401, et seq.) 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, for revocation of the approval to operate under the terms of this permit, or for denial of an application to renew this permit. All terms and conditions (excluding state-only requirements) are enforceable by the DEQ, by EPA, and by citizens under section 304 of the Clean Air Act. This permit is valid for operations only at the specific location listed.
[40 CFR §70.6(b), OAC 252:100-8-1.3 and 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. [OAC 252:100-8-6 (a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

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

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. Oral notifications (fax is also acceptable) shall be made to the AQD central office as soon as the owner or operator of the facility has knowledge of such emissions but no later than 4:30 p.m. the next working day the permittee becomes aware of the exceedance. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Every written report submitted under OAC 252:100-8-6 (a)(3)(C)(iii) shall be certified by a responsible official.[OAC 252:100-8-6 (a)(3

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. Unless a different retention period or retention conditions are set forth by a specific term 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), 8-6 (c)(1), and 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 as 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, 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. [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 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.

F. Submission of quarterly or semi-annual reports required by any applicable requirement that are duplicative of the reporting required in the previous paragraph will satisfy the reporting requirements of the previous paragraph if noted on the submitted report.

G. Every report submitted under OAC 252:100-8-6 and OAC 252:100-43 shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iv)]

H. Any owner or operator subject to the provisions of NSPS shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment. [40 CFR 60.7 (b)]

I. Any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and other information required by the subpart recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance, and records. [40 CFR 60.7 (d)]

J. 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 preventative or corrective measures adopted. [OAC 252:100-8-6 (c)(4)]

K. All testing must be conducted by methods approved by the Division Director under the direction of qualified personnel. 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. [40 CFR §70.6(a), 40 CFR §51.212(c)(2), 40 CFR § 70.7(d), 40 CFR §70.7(e)(2), OAC 252:100-8-6 (a)(3)(A)(iv), and OAC 252:100-43]

L. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 CFR Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-4-5 and OAC 252:100-41-15]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original 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. 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)(A), (C)(v), and (D)]

B. The 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; and a statement that the facility will continue to comply with all applicable requirements.
[OAC 252:100-8-6 (c)(5)(C)(i)-(iv)]

C. Any document required to be submitted in accordance with this permit shall be certified as being true, accurate, and complete by a responsible official. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification 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, -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 10 days after such date.
[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, 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 as necessary to remedy deficiencies 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.

C. If “grandfathered” status is claimed and granted for any equipment covered by this permit, it shall only apply under the following circumstances: [OAC 252:100-5-1.1]

(1) It only applies to that specific item by serial number or some other permanent identification.
(2) Grandfathered status is lost if the item is significantly modified or if it is relocated outside the boundaries of the facility.

D. To make changes other than (1) those described in Section XVIII (Operational Flexibility), (2) administrative permit amendments, and (3) those not defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII), the permittee shall notify AQD. Such changes may require a permit modification. [OAC 252:100-8-7.2 (b)]

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 2

SECTION XIV. EMERGENCIES

A. Any emergency and/or 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)]

B. 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. [OAC 252:100-8-2]

C. An emergency shall constitute an affirmative defense to an action brought for noncompliance with such technology-based emission limitation if the conditions of paragraph D below are met.

[OAC 252:100-8-6 (e)(1)]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:

(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;
(4) the permittee submitted timely notice of the emergency to AQD, pursuant to the applicable regulations (i.e., for emergencies that pose an “imminent and substantial danger,” within 24 hours of the time when emission limitations were exceeded due to the

emergency; 4:30 p.m. the next business day for all other emergency exceedances). *See OAC 252:100-8-6(a)(3)(C)(iii)(I) and (II).* 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; and

(5) the permittee submitted a follow up written report within 10 working days of first becoming aware of the exceedance.

[OAC 252:100-8-6 (e)(2), (a)(3)(C)(iii)(I) and (IV)]

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)]

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. [OAC 252:100-8-2]

(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.

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]

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 7 days, or 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 subsection. [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) No person shall cause or permit the discharge of emissions such that National Ambient Air Quality Standards (NAAQS) are exceeded on land outside the permitted facility. [OAC 252:100-3]
(2) 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]
(3) 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]
(4) For all emissions units not subject to an opacity limit promulgated under 40 CFR, Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. [OAC 252:100-25]
(5) 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]
(6) 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]

(7) Volatile Organic Compound (VOC) storage tanks built after December28, 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)]

(8) 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 s

(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.

(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.

(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 Sources' 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 Oklahoma Administrative Code 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 Code of Federal Regulations (CFR) § 70.7 (h)(1). This public notice shall include notice to the public that this permit is subject to Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 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 CFR § 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 CFR § 70.8(a) and (c).

(5) The DEQ complies with 40 CFR § 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 CFR § 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 CFR § 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]