OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **February 2, 2009**

TO:	Phillip Fielder, P.E., Permits and Engineering Group Manager, Air Quality Division
THROUGH:	Kendal Stegmann, Senior Environmental Manager, Compliance and Enforcement
THROUGH:	Phil Martin, P.E., Engineering Section
THROUGH:	Peer Review
FROM:	John Howell, P.E., Existing Source Permit Section
SUBJECT:	Evaluation of Permit Application **No. 2007-042-C (PSD)** ConocoPhillips Company, Ponca City Refinery Refinery Upgrade Projects Ponca City, Kay County, Oklahoma Latitude 36.700°, Longitude -97.087°

SECTION I. INTRODUCTION

ConocoPhillips Company owns and operates the Ponca City Refinery (the 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/North Plant/Main Power Plant, South Plant, Coker Combo/Alkylation, 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 is operated under Permit Number 98-104-TV, which was issued on December 13, 2007. 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 under 40 CFR Part 63, Subpart CC (MACT I) and Subpart UUU (MACT II). The refinery is also subject to the emissions reduction agreements of Consent Decree No. H-01-4430 (the Consent Decree) entered in the Southern District Court for Texas on April 30, 2002, amended on August 5, 2003, and amended on October 24, 2006.

ConocoPhillips submitted an application on January 26, 2007 to construct several upgrade projects at the refinery. The application was updated on February 15, 2008 to remove five of the proposed projects that have been canceled, to remove three of the proposed projects that were determined by AQD not to require a construction permit, and to include two additional projects. The application update was revised on October 7, 2008 to remove an additional project that had been cancelled as well as update the scopes of the remaining projects.

SECTION II. PROJECT SUMMARY

Projects

ConocoPhillips has requested a construction permit to install the following projects:

1. Convert the Bender unit into a Merox™ unit;
2. Add three leased boilers with heat input capacities of 95 MMBTU/hr each to provide supplemental steam to the Refinery process units. These boilers will temporarily replace two old boilers (vintage 1959 and 1971) which are to be shutdown per the Consent Decree.
3. Make metallurgical changes to the No. 1 Crude Topping Unit (CTU) in order for the unit to comply with the ConocoPhillips corporate sulfidation standard (sulfidation is the direct corrosion of metal surfaces by sulfur at temperatures above about 450°F). The project will not remove existing hydraulic bottlenecks. As such, the No. 1 CTU will not experience an increase in capacity or emissions as a result of this project
4. Make metallurgical changes to the No. 4 CTU in order for the unit to also comply with a new ConocoPhillips corporate sulfidation standard as well as increase the unit's allowable crude feed sulfur. As with the No. 1 CTU, this project will not remove existing unit hydraulic bottlenecks. As such, the No. 4 CTU will not experience an increase in capacity or emissions as a result of this project.

   In additional to metallurgical changes, the No. 1 and No. 4 CTU projects will replace old process heaters H-3, H-4, and H-5 (vintage 1929, 1945, and 1940, respectively) with new, energy efficient equipment that will reduce fuel gas usage, which will, in turn, reduce emissions of combustion-related pollutants.
5. Install a Benzene Reduction Project to reduce gasoline benzene. This project is necessary for the refinery to comply with the EPA rule to limit toxic emissions from mobile sources; specifically to limit the average levels of benzene in gasoline sold in the U.S. to 0.62 (vol%) by 2011. The project will include, among other things, installation of a new reformate splitter tower with a new fuel gas-fired reboiler, installation of a new Pressure Swing Adsorber (PSA) unit and modification the No. 2 Isomerization Unit to limit the benzene content in gasoline to comply with revised U.S. EPA standards.

The projects listed above are all independent of each other and are only related by the fact that they occur within the same contemporaneous window, i.e. they are scheduled to be installed within the same period of time.

The Ponca City Refinery also plans to add steam tubes, waste heat boilers, and air preheaters to a number of heaters as part of a heater energy recovery project to improve heat recovery efficiency. These projects will not impact emissions and were approved under Applicability Determination No. 98-104-AD (M-1). Because this and other Applicability Determinations mentioned earlier are contemporaneous with the projects included in this permit, they have been included in the netting analysis.

PSD Applicability

NO_X and SO_2 emission decreases resulting from compliance with the Consent Decree are not creditable for PSD netting purposes, but all other emissions decreases, including those for CO, PM_{10}, and VOC, are creditable.

Increases in SO_2 emissions from the Refinery Upgrade Projects are below the PSD Significant Emissions Rate (SER), and so no PSD netting analysis was required. As shown in Table II-1, net emissions increases for these projects exceed the PSD SER for NO_X and CO only. The projects, when combined with other planned and completed projects in the contemporaneous netting period, show a net reduction in PM_{10} emissions. The net emissions increase for VOC is below the PSD SER. The PSD review for this permit also requires an air quality analysis to estimate the ambient impacts of emissions from the projects (OAC 252:100-8-35). A full PSD analysis including an air quality analysis is presented in Section V of this memorandum.

Table II-1. Net Emissions Increase for PSD Regulated Pollutants

Pollutant	Emission Rate, TPY	PSD Significant Emission Rate, TPY	Subject to PSD Review?
CO	203.6	100	Yes
PM_{10}	-115.4	15	No
NO_X	51.1	40	Yes
VOC	35.0	40	No

BACT

As part of the PSD review process, a Best Available Control Technology (BACT) analysis is required for each pollutant that is emitted in excess of its PSD SER. The BACT analysis is based on the most effective technology currently available, with consideration given for energy, environmental, and economic factors. The results of the BACT analysis form the basis for the selection of control technology and the resulting emission limitations for each emissions unit. The BACT analyses for the new and modified emissions units for these projects are summarized in Table II-2. A detailed discussion of the BACT analyses is given in Section V of this memorandum.

Table II-2. Summary of Proposed BACT

Equipment	Pollutant	Emissions Rate, lb/MMBtu	BACT Description
Process Heaters	NO_X	0.03	Ultra Low NO_X Burners (ULNB)
	CO	0.04	ULNB and Good Combustion Practice
Leased Boilers	NO_X	0.036	Ultra Low NO_X Burners (ULNB)
	CO	0.04	ULNB and Good Combustion Practice

$PM_{2.5}$ Compliance

The Federal EPA finalized the PSD $PM_{2.5}$ regulations in May 2008. In the Federal Register notice announcing this regulation (Federal Register/ Vol. 73, No. 96/ Friday, May 16, 2008), EPA provided for a transition period to implement the new $PM_{2.5}$ program in SIP-approved States such as Oklahoma. EPA allowed SIP-approved States three years to develop an approved PSD $PM_{2.5}$ program and allowed them to continue implementing the PM_{10} program as a surrogate for meeting $PM_{2.5}$ NSR requirements during the SIP development process. Oklahoma DEQ has not modified their SIP as of this date and has not received Federal guidance requesting review of permits for $PM_{2.5}$. The net PM_{10} emissions resulting from the Refinery Upgrade Projects and all contemporaneous activities (-115.3 tpy) are projected to be less than the 15 tpy PM_{10} PSD threshold and do not trigger the PM_{10} program. In accordance with EPA's guidance and given the projected PM_{10} emissions, the projects included in this permit application do not trigger PSD for $PM_{2.5}$.

Flare PSD Applicability

Many of the new pieces of equipment installed by the Refinery Upgrade Projects will include pressure relief valves (PRVs) that will be connected to the Ponca City Refinery West Plant/North Plant (WP/NP) flare gas recovery unit (FGRU). The PRVs provide overpressure protection for equipment and do not release gases to the WP/NP FGRU under normal operating conditions. As such, the PRV connections will not increase flow to the WP/NP FGRU under normal operating conditions and, thus, will not increase flow or flow capacity to or expected emissions from the WP/NP Flare.

The Refinery Upgrade Projects are not projected to have an increase in malfunction events resulting in releases at the WP/NP flare. As a result of its Consent Decree with the EPA, the Ponca City Refinery has implemented a vigorous flare minimization program, resulting in a significant decrease in malfunction events. In addition, these projects will result in improved environmental performance due to replacement of old, energy inefficient heaters and boilers with new equipment which are also expected to have greater reliability. As such, because there are no projected emission increases from the WP/NP flare, the flare is not subject to PSD review.

SECTION III. PROCESS AND PROJECT DISCRIPTIONS

The ConocoPhillips Ponca City Refinery is a fully integrated facility operating three crude units, two fluidized catalytic cracking units, a coker, and other major upgrading units to produce petrochemical feedstocks, gasoline, heating oil, residual fuels, petroleum coke, and other miscellaneous petroleum products. The refinery is a modern, full upgrading facility. Major process units include:

- Fluid catalytic cracking units to upgrade gas oil to gasoline and diesel fuel;
- Alkylation, polymerization and catalytic reforming units to produce high octane gasoline blending components;
- A coker to crack/convert residuals into lighter hydrocarbon compounds and produce anode grade coke for aluminum manufacturing;
- Multiple desulfurization units; and
- Amine contactors and regenerators to remove sulfur from products and intermediates, allowing production of low sulfur products from high sulfur feedstocks.

The following sections describe the process units affected by the proposed projects.

Bender Conversion Project

There are three essential functions of the Bender process: sweetening, washing, and dehydration.

Kerosene feed is pumped from storage into the system. A portion of the feed pump discharge passes through a sulfur absorber where it becomes saturated with sulfur. This sulfur-rich stream returns to the feed pump suction where it mixes with the main feed stream.

The feed stream is preheated before entering the Bender reactor along with an air stream. Caustic (sodium hydroxide or NaOH) is also added to the feed ahead of the reactors to neutralize any hydrogen sulfide (H_2S). Small streams of caustic are also injected into the reactors to help maintain catalyst activity. In the reactor, the mercaptans in the feed convert to disulfides. Disulfides have a less offensive odor than mercaptans. A disulfide stream is considered "sweet" in relation to a mercaptan "sour" stream because of the less offensive odor.

The sweetened reactor product is cooled by non-contact heat exchange with cooling water. Fresh water is injected continuously into the stream to wash the product. Water washing removes residual caustic and any other water-soluble impurities. The two-phase product flows through an electrostatic separator.

From the electrostatic separator, the treated product flows through a sand filter to remove particulate material. The product stream continues to a salt dryer where some of the dissolved water is absorbed by the salt. This process effectively reduces the saturation temperature of the product to below the storage temperature preventing water from settling out in storage.

Finally, the dehydrated, but not anhydrous, product is filtered in clay filters to remove remaining particulate and impurities that could adversely affect the color of the product.

This project will convert the Bender unit to a Merox™ unit to produce jet fuel. As with the Bender, a Merox™ unit is a sweetening process in that it converts mercaptans to disulfides. Both processes include a caustic prewash to reduce hydrogen sulfide present in the kerosene feed. Each process also includes a clean-up train (i.e. washing and dehydration), which includes water wash, followed by salt filters and clay filters. The current Bender clean-up train will be adequate for the new Merox™ system. The major difference between the two processes is that the Bender requires the addition of sulfur oil while the Merox™ does not.

As with the Bender, kerosene feed is pumped from storage into the system. The feed stream passes through a water-cooled heat exchanger to reduce its temperature and then through a coalescer to remove free water. Caustic is added to the feed exiting the coalescer to neutralize any H_2S and remove naphthenic acids. The stream then passes through an electrostatic separator to remove the caustic and any remaining water. The feed stream exits the electrostatic separator and is sent to the reactor section of the unit.

The Merox™ process consists, primarily, of a fixed-bed reactor/caustic settler. Air and liquid Merox Plus™ activator, which is used to extend catalyst life and provide additional catalytic activity when treating more difficult feedstocks, are injected into the kerosene feedstock upstream of the reactor. The mixture enters the top of the reactor and flows downward through the catalyst bed into the bottom portion of the vessel which serves as a caustic settler. The caustic settler contains a reservoir of caustic for use in keeping the Merox™ catalyst alkaline. The caustic is periodically circulated over the reactor bed while maintaining operations.

Leased Boilers Project

The Refinery plans to add three leased boilers, each having a steam generating capacity of 60,000 lbs/hr of 600 PSIG steam (approximately 95 MMBTU/Hr fired duty capacity per boiler), to provide supplemental steam to the Refinery process units. The boilers will be fired with pipeline quality natural gas and will include NO_X controls.

The leased boilers will temporarily replace two old boilers (vintage 1959 and 1971) which are to be shut down as required by the Consent Decree. The leased equipment will be more energy efficient, which will reduce fuel gas usage, This will, in turn, reduce emissions of combustion-related pollutants.

No. 1 CTU Sustaining Project

The No. 1 Crude Topping Unit (CTU) is one of three crude units in the refinery that process raw crude oil in parallel. Crude topping units are the first major refinery processes that meet crude oil and fractionate it into several streams representing different boiling fractions. These streams are normally charged to downstream units for further processing. For simplification, the No. 1 CTU can be divided into five basic sections; preheat train and desalter, preflash drum, atmospheric crude tower, tar stripper, and vacuum tower.

Raw crude oil is pumped with charge pumps through the raw crude preheat train, which is a series of heat exchangers that transfer heat from the CTU product, pump-around, and recycle streams to the raw crude oil, and to the crude oil desalters. The desalters use temperature, pressure, injected water, emulsion breaker chemicals, electric fields, and residence time to remove metallic salts, water, and other impurities, thereby preventing fouling of downstream heat exchangers, salt formation in furnaces, and equipment corrosion.

The crude oil from the desalters is pumped by desalted crude pumps through two more preheat trains that operate in parallel. Hot crude from the two preheat trains combines and flows to crude flash drum, D-29.

By the reduction of pressure, part of the hot crude oil (the lighter, more volatile fractions) is vaporized in the crude flash drum and flows to crude tower W-1. The hot liquid from the crude flash drum is pumped through additional heat exchangers and then crude charge furnace H-1 before entering W-1.

Crude Tower W-1 uses distillation to remove the lightest gravity products from the crude oil. The product streams from W-1 are wet gas overhead, light straight run gasoline (LSR), reforming naphtha, kerosene, heating oil distillate (HOD), atmospheric gas oil, and reduced crude tower bottoms.

The crude tower bottoms stream is heated in furnace H-5 and then fed to tar stripper tower W-21. The tar stripper tower uses an atmospheric flash to remove light gas oil (LGO) and heavy gas oil (HGO) from the reduced crude. The tar stripper bottoms stream is heated in vacuum furnace H-16 and then fed to vacuum tower W-17.

The No. 1 CTU vacuum tower uses sub-atmospheric pressures to separate the remaining heavy hydrocarbons into light vacuum gas oil (LVGO), heavy vacuum gas oil (HVGO) and a resid bottoms product stream.

The objective of the No. 1 CTU Sustaining Project is to enable the unit to comply with the corporate Sulfidation Service Equipment Required Standard (sulfidation means the direct corrosion of metal surfaces by sulfur at temperatures above about 450°F) while maintaining the current maximum allowable crude oil feed sulfur at 1.5 wt%. The project is also intended to enable the No. 1 CTU to comply with the corporate Atmospheric Overhead Corrosion Control Required Standard as well as addressing inspection-driven equipment replacements. The project involves replacing existing metals with more corrosion-resistant materials where necessary for this service.

In addition to complying with the corporate sulfidation standard, the project will improve energy efficiency and reduce environmental emissions by replacing Tar Stripper Furnace H-5 with a modern furnace that provides process heat input and generates steam from waste heat.

<u>No. 1 CTU Sustaining Project - Sulfidation Standard Scope</u>

As mentioned above, the No. 1 CTU Sustaining project upgrades the unit's fixed equipment consistent with the Sulfidation Service Equipment Standard. Sulfidation equipment scope includes two shell & tube heat exchanger replacements and two pump replacements with more corrosion-resistant materials. Tar Stripper Furnace H-5, a gas-fired heater over 60 years old with poor energy efficiency and high maintenance, will also be replaced. A recent (4th Quarter 2007) inspection of the furnace identified required repairs that were estimated to be >50% of the cost of a new furnace. As such, the decision was made to replace the heater with new, more energy efficient equipment. The new heater will include NOx controls, a safety instrument system, and a fuel gas coalescer system. In addition, because the new equipment will be more energy efficient, it will reduce fuel gas usage, which will, in turn, reduce emissions of combustion-related pollutants.

<u>No. 1 CTU Sustaining Project - Atmospheric Overhead Corrosion Control Standard Scope</u>

In order to comply with the Atmospheric Overhead Corrosion Control Standard, the No. 1 CTU crude tower W-1 will need to operate at an increased overhead temperature which serves to minimize corrosion potential. This elevated temperature will, in turn, increase the amount of naphtha-range material in the LSR liquid stream. As such, the following changes will need to be made to No. 7 Hydrotreater (HDT) LSR/Naphtha splitter column W-42 in order to handle the additional naphtha-range material:

- Re-tube the tower overhead air-cooled heat exchanger;
- Relocate the tower steam reboiler suction line from the bottom of W-42 to the side of the tower in order to minimize plugging of the reboiler with corrosion products, loose tray parts, etc. from the tower; and
- Replace the W-42 upper section fractionation trays to reduce flooding caused by the increased liquid rates in that section.

These changes are necessary to ensure adequate separation of the LSR and Naphtha product streams. They will not, however, result in additional production of LSR or Naphtha.

<u>No. 1 CTU Sustaining Project - Mechanical Integrity Scope</u>

The Ponca City Refinery Inspection Group has identified the following major pieces of fixed equipment that will require replacement:

- Crude Preflash Drum, D-29;
- Lower Portion Of Atmospheric Crude Tower, W-1; and
- Atmospheric Crude Tower Overhead Condensers, X-13/14/16

While the No. 1 CTU Sustaining project will increase the unit's resistance to corrosion by sulfur, it will not remove existing unit bottlenecks including, but not limited to, flow capacity of the raw crude charge pumps, pressure drop across the raw crude preheat train (both heat exchangers and control valves), insufficient heat exchanger surface area necessary for adequate incremental product stream cooling, crude charge furnace H-1 heat input capacity, crude tower overhead heat exchanger cooling capacity, and many others. As such, the unit will not experience an increase in capacity or emissions as a result of this project.

No. 4 CTU Revamp Project

As with the No. 1 CTU, the No. 4 CTU is one of three crude units in the refinery that process raw crude oil in parallel. Crude topping units are the first major refinery processes that meet crude oil and fractionate it into several different boiling fractions. These streams are normally charged to downstream units for further processing.

The No. 4 CTU is made up of three basic sections; crude preheat train, which is a series of shell-and-tube heat exchangers that transfer heat from the CTU product, pumparound, and recycle streams to the raw crude oil and to the crude oil desalter, atmospheric distillation, and vacuum distillation.

Shell-and-tube heat exchangers preheat the raw crude oil from storage to the operating temperature of the desalter. The desalter removes metallic salts, water and other impurities to prevent fouling of exchangers, coke formation in the furnaces, and equipment corrosion. The remainder of the heat exchanger train heats the desalted crude to the operating temperature of the atmospheric distillation section.

The main equipment in the No. 4 CTU atmospheric distillation section are “A” tower (W-22), “B” tower (W-24), and “C” tower (W-27). “A” tower separates the lightest product streams from the desalted crude stream. The “A” tower product streams include wet gas overhead, light straight run gasoline (LSR), and a side draw of light naphtha (Atmospheric Reforming Naphtha or ARN).

The “A” tower bottoms stream is fed to “B” tower where it is separated into kerosene ,a side draw of atmospheric gas oil (AGO), and an overhead vapor stream and a heating oil distillate (HOD) stream which are both fed to “C” tower for further fractionation. The “B” tower bottoms product stream is fed to the No. 4 CTU vacuum system.

“C” tower separates the “B” tower overhead vapor stream and HOD side draw stream into an overhead product of reforming naphtha (CRN), a kerosene side draw product stream, and a HOD bottoms product stream.

The No. 4 CTU vacuum distillation section uses sub-atmospheric pressures to separate the remaining heavy hydrocarbons into waxy gas oil (WGO) product streams and lube resid. The main equipment in the vacuum distillation system are W-18 tower and W-19 tower. The W-18 tower fractionates the “B” tower bottoms stream into an overhead product stream that is fed to W-19 for further fractionation, a side draw product of waxy gas oil (350 WGO) and a resid bottoms product stream. The W-19 tower fractionates the W-18 overhead vapor stream into an overhead product stream of waxy gas oil (W19 WGO) and a bottoms product stream of slightly heavier waxy gas oil (200 WGO).

The primary objective of the No.4 CTU Revamp Project is to maintain the unit's crude charge by complying with the Sulfidation Service Equipment Required Standard as well as addressing Inspection driven equipment replacements. In addition, replacement of the vacuum furnace, when combined with the sulfidation metallurgy upgrades, increases the maximum allowable crude sulfur from 0.3 wt% to 1.0 wt%. The basis for the high-sulfur crude slate is 50% West Texas Sour (WTS) and 50% Oklahoma Sweet. The refinery amine contacting and regenerating systems have more than sufficient capacity to handle any increase in acid gas (i.e. hydrogen sulfide, or H2S) resulting from the increase in the No. 4 CTU maximum allowable crude feed sulfur. In addition, there is also more than sufficient capacity in the refinery H2S collecting/handling system to accommodate the delivery of additional acid gas to off-site processing.

The project also improves energy efficiency and reduces environmental emissions by replacing the atmospheric and vacuum furnaces, H-3 and H-4.

<u>No. 4 CTU Revamp Project – Sustaining – Sulfidation Scope</u>

The Revamp project upgrades the metallurgy of piping and fixed equipment in the No. 4 CTU consistent with the Sulfidation Service Equipment Required Standard. Sulfidation scope includes alloy upgrades for

- 8 shell & tube heat exchangers,
- 3 pumps and
- Approximately 1,300 ft. of large bore piping.

<u>No. 4 CTU Revamp Project – Sustaining – Mechanical Integrity Scope</u>

The Ponca City Refinery Inspection Group has identified several pieces of equipment that will require replacement. The key pieces of equipment that require replacement include

- <u>Atmospheric furnace H-4.</u>
- <u>HVGO/Resid Product Box Cooler, and</u>
- <u>Several product rundown coolers.</u>

The No. 4 CTU Atmospheric Tower Furnace, H-4, radiant tubes are estimated to reach end of life based on service hours and sulfur corrosion before 2017. As such, the decision was made to replace the existing furnace with new equipment that will include NO_X controls, a safety instrument system, continuous emission monitoring equipment, and a fuel gas coalescer system.

No. 4 CTU Revamp Project – Metallurgy Scope

The No.4 CTU Vacuum Tower Furnace, H-3, will be replaced in order to meet the crude oil 1.0 wt% sulfur design basis. The new heater will include NO_X controls, a safety instrument system, and a fuel gas coalescer system.

Because the two new heaters will be more energy efficient, they will reduce fuel gas usage, which will, in turn, reduce emissions of combustion-related pollutants.

The No. 4 CTU Revamp project will increase the unit's resistance to corrosion by sulfur, but will not remove existing unit bottlenecks including, but not limited to, flow capacity of the unit's raw and desalted crude charge pumps, pressure drop across the unit's raw crude preheat train, and many others. As such, the unit will not experience an increase in capacity or emissions as a result of this project.

Benzene Reduction Project

On February 6, 2007, the U.S. EPA finalized a rule to limit toxic emissions from mobile sources. This rule includes provisions to limit the average levels of benzene in gasoline sold in the U.S. to 0.62 (vol%) by 2011. The Refinery will be required to install new equipment and modify current equipment to accommodate the new benzene content regulations. The primary changes will include:

- Addition of a new Pressure Swing Adsorber (PSA) Unit;
- Addition of a new reformate splitter tower with new fuel gas-fired reboiler NH-1;
- Modification of the No. 2 Isomerization Unit, including re-traying the unit stabilizer tower, installation of two new reactors and several new/replacement heat exchangers.
- Addition or replacement of various fugitive components (compressors, pumps, valves, flanges, sample stations, wastewater hubs).

SECTION IV. PROJECT EMISSIONS

The refinery is an existing PSD major source. This section presents the emission calculation methodology used to determine PSD applicability for the new, modified, and associated sources.

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, the New Source Review (NSR) revisions in OAC 252:100-8, and the Consent Decree which places restrictions on NO_X and SO_2 pollutant emissions reductions (achieved through compliance with the Consent Decree) that can be counted in a PSD netting analysis.

A six-step procedure was used for determining the net emissions change:

1. Emissions Increases from the Project (PSD Applicability). Determine the emission increases from the project from any new sources, modified sources, and associated sources

(i.e. debottlenecked units). If increases are above PSD Significant Emission Rates (SERs), proceed, if not, the project is not subject to PSD review for that pollutant.

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 Emissions Increases and Decreases. Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.

6, PSD Review Applicability. 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.

Step 1. Emissions Increases from the Project (PSD Applicability)

The maximum potential emissions from each new, modified, and associated source were determined for this project. For each PSD pollutant, the baseline actual emissions as defined in OAC 252:100-8-31(b) were subtracted from the potential emissions to determine the emissions increase for each new, modified, or associated source. For new emissions sources the baseline actual emissions are zero. For these projects, ConocoPhillips selected the years 2004 and 2005 for calculation of any baseline actual emissions. Emission decreases are not considered in this step. The emissions increases for each new, modified, and associated source are shown in the following sections.

New Process Heaters and Boilers

The proposed projects will include four new refinery fuel gas (RFG)-fired process heaters (NH-1, NH-3, NH-4, and NH-5) and three pipeline quality natural gas-fired high pressure steam boilers (TB-1, TB-2, and TB-3). The boilers are necessary to replace the steam production capacity that will be lost due to the shutdown of existing boilers B-0006 and B-0007 during the second half of 2009. The refinery heaters will be equipped with $ULNO_X$ burners and the leased boilers are equipped with NO_X control equipment such as, but not limited to, $ULNO_X$ burners and flue gas recirculation. Table IV-1 lists parameters for the new process heaters and boilers.

Table IV-1. New Process Heaters and Boilers

ID	Description	Rating , MMBtu/hr
NH-1	New Naphtha Splitter Reboiler	131.3
NH-3	New No. 4 CTU Vacuum Heater	45.0
NH-4	New No. 4 CTU Crude Heater	125.0
NH-5	New No. 1 CTU Tar Stripper Heater	98.0
TB-1	Leased Steam Boiler No. 1	95.0
TB-2	Leased Steam Boiler No. 2	95.0
TB-3	Leased Steam Boiler No. 3	95.0

Potential emissions are based on continuous operation. Estimated emissions of PM_{10} and VOC are based on AP-42 (7/98), Tables 1.4-1 and 1.4-2 for natural gas combustion. Estimated emissions of SO_2 from heaters NH-1, NH-3, NH-4, and NH-5 are based on fuel sulfur standards for the proposed NSPS Subpart Ja, which is 60 ppmv H_2S for a 365-day rolling average. Estimated emissions of SO_2 from the leased boilers TB-1, TB-2, and TB-3 are based on combustion of pipeline grade fuel gas. Estimated emissions of NO_X and CO are based on the BACT rates listed in Table II-2 above.

Table IV-2. Emissions Increases for New Process Heaters & Boilers

Emission Unit	Max Heat Rate, MMBtu/hr (HHV)	Pollutant	Emission Factor, lb/MMBtu (HHV)	Potential Emissions		Actual Emissions	Net Increase
				lb/hr	TPY	TPY	TPY
New Naphtha Splitter Reboiler NH-1	131.3	NO_X	0.030	3.94	17.3	0.0	17.3
		SO_2	0.012	1.58	6.9	0.0	6.9
		CO	0.040	5.25	23.0	0.0	23.0
		VOC	0.0054	0.71	3.1	0.0	3.1
		PM_{10}	0.0075	0.98	4.3	0.0	4.3
New No. 4 CTU Vacuum Heater NH-3	45.0	NO_X	0.030	1.35	5.9	0.0	5.9
		SO_2	0.012	0.54	2.4	0.0	2.4
		CO	0.040	1.80	7.9	0.0	7.9
		VOC	0.0054	0.24	1.1	0.0	1.1
		PM_{10}	0.0075	0.34	1.5	0.0	1.5
New No. 4 CTU Crude Heater NH-4	125.0	NO_X	0.030	3.75	16.4	0.0	16.4
		SO_2	0.012	1.50	6.6	0.0	6.6
		CO	0.040	5.00	21.9	0.0	21.9
		VOC	0.0054	0.68	3.0	0.0	3.0
		PM_{10}	0.0075	0.94	4.1	0.0	4.1
New No. 1 CTU Tar Stripper Heater NH-5	98.0	NO_X	0.030	2.94	12.9	0.0	12.9
		SO_2	0.012	1.18	5.2	0.0	5.2
		CO	0.040	3.92	17.2	0.0	17.2
		VOC	0.0054	0.53	2.3	0.0	2.3
		PM_{10}	0.0075	0.74	3.2	0.0	3.2

Emission Unit	Max Heat Rate, MMBtu/hr (HHV)	Pollutant	Emission Factor, lb/MMBtu (HHV)	Potential Emissions		Actual Emissions	Net Increase
				lb/hr	TPY	TPY	TPY
TB-1 Leased Steam Boiler	95.0	NO_X	0.036	3.42	15.0	0.0	15.0
		SO_2	0.0005	0.05	0.2	0.0	0.2
		CO	0.040	3.80	16.6	0.0	16.6
		VOC	0.0054	0.51	2.2	0.0	2.2
		PM_{10}	0.0075	0.71	3.1	0.0	3.1
TB-2 Leased Steam Boiler	95.0	NO_X	0.036	3.42	15.0	0.0	15.0
		SO_2	0.0005	0.05	0.2	0.0	0.2
		CO	0.040	3.80	16.6	0.0	16.6
		VOC	0.0054	0.51	2.2	0.0	2.2
		PM_{10}	0.0075	0.71	3.1	0.0	3.1
TB-3 Leased Steam Boiler	95.0	NO_X	0.036	3.42	15.0	0.0	15.0
		SO_2	0.0005	0.05	0.2	0.0	0.2
		CO	0.040	3.80	16.6	0.0	16.6
		VOC	0.0054	0.51	2.2	0.0	2.2
		PM_{10}	0.0075	0.71	3.1	0.0	3.1
Total		NO_X					97.5
		SO_2					21.7
		CO					119.8
		VOC					16.1
		PM_{10}					22.4

<u>New Fugitive Emissions</u>

All of the proposed projects, except for the leased boilers, will result in an increase in VOC emissions from equipment leaks due to the installation of equipment such as flanges, valves, compressors, drains, and pumps. Fugitive emitting equipment is associated with each of the proposed projects. The emissions increases for equipment leaks were calculated using design-basis fugitive counts along with emission factors that were developed specifically for the Ponca City Refinery. The factors are given in Table 2-1 in a March 1, 1991 letter from Conoco to DEQ titled “Refinery Specific Fugitive Emission Factors – Ponca City Refinery.” Sewer component (QQQ) emission factors are from AP-42, Fourth Edition, 9/85, and “VOC Emissions from Petroleum Refinery Wastewater Systems – Background Information for Proposed Standards”, EPA-450/3-85-001a, 2/85. Flare control efficiency is 98% for relief valves with leakage vented to a flare. Tables IV-3 through IV-5 present the VOC emissions increase from fugitive emissions from new construction for these projects.

Table IV-3. No. 1 CTU Sustaining Project and No. 4 CTU Revamp Project Fugitive Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	190	0.00253	0.481	2.11
Light liquid valves	250	0.00468	1.17	5.12
Heavy liquid valves	250	0.00051	0.128	0.56
Flanges	2484	0.00013	0.323	1.41
Light liquid pumps	0	0.04509	0	0
Heavy liquid pumps	5	0.04718	0.236	1.03
Gas compressors	0	0.50265	0	0
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare	2	0.00459	0.009	0.04
Sample Stations	0	0.03307	0	0
QQQ Components Added:				
Process drains (controlled)	10	0.03500	0.35	1.53
Junction (or water draw) boxes (controlled)	0	0.07000	0	0
Overall Emissions Increase			**2.697**	**11.80**

Table IV-4. Benzene Reduction Project Fugitive Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	360	0.00253	0.911	3.99
Light liquid valves	360	0.00468	1.685	7.38
Heavy liquid valves	0	0.00051	0	0
Flanges	2592	0.00013	0.337	1.48
Light liquid pumps	0	0.04509	0	0
Heavy liquid pumps	8	0.04718	0.377	1.65
Gas compressors	1	0.50265	0.503	2.20
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare	23	0.00459	0.106	0.46
Sample Stations	11	0.03307	0.364	1.59
QQQ Components Added:				
Process drains (controlled)	35	0.03500	1.225	5.37
Junction (or water draw) boxes (controlled)	10	0.07000	0.700	3.07
Overall Emissions Increase			**6.108**	**27.19**

Table IV-5. Bender Conversion Project
Fugitives Equipment Parameters and Emissions

Type of Component	Number of Components	Emission Factors, lb/hr-source	VOC, lb/hr	VOC, TPY
GGG Components Added:				
Gas valves	20	0.00253	0.051	0.22
Light liquid valves	40	0.00468	0.187	0.82
Heavy liquid valves	500	0.00051	0.255	1.12
Flanges	2016	0.00013	0.262	1.15
Light liquid pumps	4	0.04509	0.180	0.79
Heavy liquid pumps	10	0.04718	0.472	2.07
Gas compressors	0	0.50265	0	0
Gas relief valves to atmosphere	0	0.22928	0	0
Gas relief valves to flare	20	0.00459	0.092	0.40
Sample Stations	5	0.03307	0.165	0.72
QQQ Components Added:				
Process drains (controlled)	40	0.03500	1.400	6.13
Junction (or water draw) boxes (controlled)	10	0.07000	0.700	3.07
Overall Emissions Increase			**3.764**	**16.49**

Associated Units

In the original PSD permit application, submitted January 26, 2007, the projects that were included would have resulted in numerous debottleneck removals that would, in turn, have resulted in associated emissions increases. However, current market conditions and changes in corporate strategies have led ConocoPhillips to adjust its project construction plans. As a result, several of the projects were cancelled or were determined by AQD to not require permitting. The scopes of the remaining Bender Conversion project, the new No. 1 CTU Sustaining Project, the No. 4 CTU Revamp project, the Leased Boilers project, and the Benzene Reduction project are such that they will not result in any increased emissions from any other of the refinery process units.

As discussed in Section III, the No. 1 CTU Sustaining project and the No. 4 CTU Revamp project will increase the unit's resistance to corrosion by sulfur; however, they will not remove existing unit bottlenecks including, but not limited to, flow capacity of unit crude charge pumps, pressure drop across crude preheat train (both heat exchangers and control valves), and many others. As such, neither the No. 1 CTU nor the No. 4 CTU will experience an increase in capacity as a result of these projects. Consequently, there will be no emissions resulting from debottlenecking and, therefore, no associated emissions resulting from these projects.

Regarding No. 1 CTU process heaters H-0001 and H-0016, which will not be modified or otherwise changed as a result of the No. 1 CTU Sustaining project, because the project will not change the crude slate or crude rate currently processed in the unit, nor will it result in any changes to the fuel gas burned in the two heaters, their emissions will not change. Therefore, there no associated emission from these sources as a result of the project.

The Benzene Reduction project will add additional treatment of existing process streams in order to make the refinery compliant with the EPA rule to limit toxic emissions from mobile sources (finalized in February, 2007); specifically to limit the average levels of benzene in gasoline sold in the U.S. to 0.62 vol% by 2011. This project will not increase capacity of any refinery process units. As such, there will be no emissions resulting from debottlenecking and, therefore, no associated emissions will result from this project.

The leased boilers will replace the steam currently supplied by old boilers B-6 and B-7, which are to be shut down by the end of July, 2009. The two existing boilers are currently used as back up boilers in case of emergencies and are limited to specific annual fired duties that are the equivalent of less than 2 months per year continuous operation. As such, replacement of B-6 and B-7 with the leased equipment will not increase the capacities of, i.e., debottleneck, any other process units or sources in the refinery and, therefore, there are no associated emissions resulting from this project.

Lastly, the Bender Conversion project will convert the existing kerosene treatment unit to a Merox™ process, but will not increase the capacities of, i.e. debottleneck, any refinery process units. As such, there are no associated emissions resulting from this project.

PSD Applicability

Table IV-6 shows the total applicable emissions increase for each PSD regulated pollutant. Each emissions increase is the sum of the emissions increases for each pollutant in Tables IV-2, IV-3, IV-4, and IV-5 above. The total project emissions increase for each pollutant is compared to the PSD Significant Emission Rate (SER) for that pollutant to determine if a PSD netting analysis is required. As shown in Table IV-6, the project emissions increases for NO_X, CO, VOC, and PM_{10} are above the respective SER. Therefore, a PSD netting analyses, based on steps 2 through 6 of the PSD netting procedure, is required for each of those pollutants.

Table IV-6. Project Emissions Increase for PSD Regulated Pollutants

Pollutant	Emission Rate, tpy	PSD Significant Emission Rate, tpy	PSD Netting Analysis Required?
NO_X	97.5	40	Yes
SO_2	21.7	40	No
CO	119.8	100	Yes
VOC	71.6	40	Yes
PM_{10}	22.4	15	Yes

Step 2. Contemporaneous Period

According to OAC 252:100-8-31, *"an increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within 3 years before the date that the increase from the particular change occurs".* In agreement with recent discussions with the DEQ, ConocoPhillips has interpreted the contemporaneous period to be three years prior to the start of construction through the start of operation of the final element of the benzene reduction project. Therefore, for the Refinery Upgrade Projects, the contemporaneous period begins January 1, 2004 and ends December 31, 2010.

Step 3. Emissions Increases and Decreases during the Contemporaneous Period

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 begin operation during the contemporaneous period.

ConocoPhillips determined contemporaneous emission increases and decreases through a review of the current refinery permit history and future planned refinery projects. A summary of the contemporaneous emissions increases and decreases is provided in Table IV-7. As mentioned previously, not all emissions changes included in Table IV-7 are creditable. SO_2 emissions are shown for convenience only, since a netting analysis is not required.

Table IV-7. Summary of Contemporaneous Emissions Increases and Decreases

Year	Description	Emission Increases or Decreases, TPY				
		CO	PM_{10}	NO_X	SO_2	VOC
2004	No. 1 CTU Upgrade	240.7	-	-	272.1	36.1
2005	H-0047 Shutdown (1)	-4.3	-0.4	-5.1	-0.1	-0.3
2006	OG&E Turbine 1 Removal (2)	-2.4	-6.5	-177.0	-4.8	-23.2
2006	OG&E Turbine 2 Removal (2)	-1.8	-5.3	-190.0	-3.6	-22.4
2006	No. 1 Cogen Duct Burner Shutdown (2)	-21.8	-10.9	-	-2.2	-27.2
2006	No. 2 Cogen Duct Burner Shutdown (2)	-20.7	-10.3	-	-2.3	-25.8
2006	ULSD & Upgrade Projects	-	55.9	412.0	372.0	-
2006	No. 5 FCCU WGS (3)	-	-159	-	-	-
2007	No. 4 CTU/CVU Upgrade	-	-	-	-	9.5
2007	No. 1 CTU H-0001 Jumper	-	-	-	-	0.5

Year	Description	Emission Increases or Decreases, TPY				
		CO	PM_{10}	NO_X	SO_2	VOC
2007	H-0011 Potential Increase	3.8	0.2	3.8	1.9	0.2
2007	H-7501 Potential Increase	1.0	0.6	11.4	4.8	0.5
2007	Coke Pad Potential Increase	-	7.6	-	-	-
2008	Refinery Hydraulic Limits	-	-	-	-	5.0
2008	South Plant Cooling Water Pump	-	2.8	-	-	3.7
2008	No. 4 FCC WGS	-	-	-	-	5.0
2008	Denatured Ethanol Tanks	-	-	-	-	10.7
2008	H-0057/0058/0059 Shutdown (4), (5)	-43.2	-3.9	-	-1.4	-2.8
2008	H-5001 Shutdown (4), (5)	-27.2	-2.5	-	-1.1	-1.8
2008-2010	H-3/H-4/H-5 Shutdown (4)	-40.3	-6.1	-101.5	-2.6	-3.0
2008-2010	Refinery Upgrade Projects (Proposed Projects) (4)	119.8	22.4	97.5	21.7	71.6

1. Heater H-0047 was permanently shutdown during the 3rd quarter of 2005.
2. The Cogen combustion turbines and HRSG duct burners were shutdown during the 1st half of 2006.
3. The No. 5 FCCU WGS was installed and put into operation during the 4th quarter of 2006.
4. ConocoPhillips estimated emissions and project timing.
5. Heaters H-0057/0058/0059 and H-5001 will be replaced by new heaters H-0060 and H-5002.

Step 4. Creditable Emissions Increases and Decreases

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 emissions increase or decrease 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 of potential emissions from an emissions unit that was permitted, but never built or operated. Table IV-8 is a summary of the contemporaneous and creditable projects relied upon in the PSD netting for the Refinery Upgrade Projects.

Emissions decreases for the No. 5 FCCU were calculated in Permit No. 2003-336-C (M-2) PSD but were thought to not be creditable because they were the result of compliance with the Consent Decree. Since then, it has been determined that the decrease in PM_{10} emissions is, in fact, an eligible credit. Therefore, ConocoPhillips has elected to take credit for the emissions decrease associated with the No. 5 FCCU for PM_{10}. Emissions decreases of NO_X and SO_2 resulting from compliance with the Consent Decree are not creditable for PSD netting. However, these decreases are accounted for in the air quality modeling.

Table IV-8. Evaluation of Contemporaneous and Creditable Projects

Year	Description	Creditable For?
2004	No. 1 CTU Upgrade (1)	CO, SO_2, VOC
2005	H-0047 Shutdown (2)	CO, PM_{10}, NO_X, SO_2, VOC
2006	OG&E Turbine 1 Removal (3)	CO, PM_{10}, NO_X, SO_2, VOC
2006	OG&E Turbine 2 Removal (3)	CO, PM_{10}, NO_X, SO_2, VOC
2006	No. 1 Cogen Duct Burner Shutdown (3), (4)	CO, PM_{10}, SO_2, VOC
2006	No. 2 Cogen Duct Burner Shutdown (3), (4)	CO, PM_{10}, SO_2, VOC
2006	ULSD & Upgrade Projects (5)	PM_{10}, NO_X, SO_2
2006	No. 5 FCCU WGS (6), (7), (8), (9)	PM_{10}
2007	No. 4 CTU/CVU Upgrade (2002-115-AD (M-3))	VOC
2007	No. 1 CTU H-0001 Jumper (2007-042-AD (M-1))	VOC
2007	H-0011 Potential Increase (98-104-AD (M-1))	CO, PM_{10}, NO_X, SO_2, VOC
2007	H-7501 Potential Increase (98-104-AD (M-1))	CO, PM_{10}, NO_X, SO_2, VOC
2007	Coke Pad Potential Increase (98-104-AD (M-1))	PM_{10}
2008	Refinery Hydraulic Limits (2007-042-AD (M-1))	VOC
2008	South Plant Cooling Water Pump (2007-042-AD (M-1))	PM_{10}, VOC
2008	No. 4 FCC WGS (2007-042-AD (M-1))	VOC
2008	Denatured Ethanol Tanks (91-031-AD (M-3))	VOC
2008	H-0057/0058/0059 Shutdown (4), (10)	CO, PM_{10}, SO_2, VOC
2008	H-5001 Shutdown (4), (10)	CO, PM_{10}, SO_2, VOC
2008-2010	H-3/H-4/H-5 Shutdown (10)	CO, PM_{10}, NO_X, SO_2, VOC

1. Only emissions of CO, SO_2 and VOC are considered creditable since emissions of PM_{10} and NO_X were previously relied upon for permit No. 2002-476-C (M-2) (PSD).
2. Heater H-0047 was permanently shutdown during the 3rd quarter of 2005.
3. The Cogen combustion turbines and HRSG duct burners were shutdown during the 1st half of 2006.
4. NO_X emission credits available from shutdown of this equipment are to be applied toward NO_X reduction activities required by the Consent Decree.
5. Only emissions of PM_{10}, NO_X, and SO_2 are considered creditable since emissions of CO and VOC were previously relied upon for permit No. 2003-336-C (M-3) (PSD).
6. The No. 5 FCCU WGS was installed and put into operation during the 4th quarter of 2006.
7. SO_2 emission credits available from startup of the WGS are to be applied toward SO_2 reduction activities required by the Consent Decree.

8. The No. 5 FCCU ESNCR was installed and put into operation during the 4th quarter of 2006.
9. NO_X emission credits available from startup of the ESNCR are to be applied toward NO_X reduction activities required by the Consent Decree.
10. ConocoPhillips estimated project timing.

Step 5. Amount of Emissions Increases and Decreases

A summary of the contemporaneous and creditable emissions increases and decreases for each PSD pollutant is presented in Table IV-9.

Table IV-9. Summary of Contemporaneous Emissions Increases and Decreases

Year	Description	Emission Increases or Decreases (TPY)				
		CO	PM_{10}	NO_X	SO_2	VOC
2004	No. 1 CTU Upgrade (1)	240.7	-	-	272.1	36.1
2005	H-0047 Shutdown (2)	-4.3	-0.4	-5.1	-0.1	-0.3
2006	OG&E Turbine 1 Removal (3)	-2.4	-6.5	-177.0	-4.8	-23.2
2006	OG&E Turbine 2 Removal (3)	-1.8	-5.3	-190.0	-3.6	-22.4
2006	No. 1 Cogen Duct Burner Shutdown (4), (5)	-21.8	-10.9	-	-2.2	-27.2
2006	No. 2 Cogen Duct Burner Shutdown (4), (5)	-20.7	-10.3	-	-2.3	-25.8
2006	ULSD & Upgrade Projects (5)	-	55.9	412.0	372.0	-
2006	No. 5 FCCU WGS (6), (7), (8), (9)	-	-159.0	-	-	-
2007	No. 4 CTU/CVU Upgrade (11)	-	-	-	-	9.5
2007	No. 1 CTU H-0001 Jumper (12)	-	-	-	-	0.5
2007	H-0011 Potential Increase (14)	3.8	0.2	3.8	1.9	0.2
2007	H-7501 Potential Increase (14)	1.0	0.6	11.4	4.8	0.5
2007	Coke Pad Potential Increase (14)	-	7.6	-	-	-
2008	Refinery Hydraulic Limits (12)	-	-	-	-	5.0
2008	South Plant Cooling Water Pump (12)	-	2.8	-	-	3.7
2008	No. 4 FCC WGS (12)	-	-	-	-	5.0
2008	Denatured Ethanol Tanks	-	-	-	-	10.7
2008	H-0057/0058/0059 Shutdown (4), (10)	-43.2	-3.9	-	-1.4	-2.8
2008	H-5001 Shutdown (4), (10)	-27.2	-2.5	-	-1.1	-1.8
2008-2010	H-3/H-4/H-5 Shutdown (10)	-40.3	-6.1	-101.5	-2.6	-4.3
	Total	**83.8**	**-137.8**	**-46.4**	**632.7**	**-36.6**

1. Only emissions of CO, SO_2 and VOC are considered creditable since emissions of PM_{10} and NO_X were previously relied upon for permit No. 2002-476-C (M-2) (PSD).
2. Heater H-0047 was permanently shutdown during the 3rd quarter of 2005.

3. The Cogen combustion turbines and HRSG duct burners were shutdown during the 1st half of 2006.
4. NO_X emission credits available from shutdown of this equipment are to be applied toward NO_X reduction activities required by the Consent Decree.
5. Only emissions of PM_{10}, NO_X, and SO_2 are considered creditable since emissions of CO and VOC were previously relied upon for permit No. 2003-336-C (M-3) (PSD).
6. The No. 5 FCCU WGS was installed and put into operation during the 4th quarter of 2006.
7. SO_2 emission credits available from startup of the WGS are to be applied toward SO_2 reduction activities required by the Consent Decree.
8. The No. 5 FCCU ESNCR was installed and put into operation during the 4th quarter of 2006.
9. NO_X emission credits available from startup of the ESNCR are to be applied toward NO_X reduction activities required by the Consent Decree.
10. ConocoPhillips estimated project timing.
11. Applicability determination 2002-115-AD (M-3).
12. Applicability determination 2007-042-AD (M-1).
13. Reserved.
14. Applicability Determination 98-104-AD (M-1).

Step 6. PSD Review Applicability

Table IV-10 summarizes the net emissions increase for each PSD pollutant for the Refinery Upgrade Projects.

Table IV-10. Net Emissions Increases from the Projects

Pollutant	Emissions Increase, TPY (1)	Creditable Contemporaneous Emissions, TPY (2)	Net Emissions Increase, TPY	PSD Significant Emission Rate, TPY	Subject to PSD Review?
CO	119.8	83.8	**203.6**	100	Yes
PM_{10}	22.4	-137.8	**-115.4**	15	No
NO_X	97.5	-46.4	**51.1**	40	Yes
VOC	71.6	-36.6	**35.0**	40	No

1. From Table IV-6
2. From Table IV-9

The project is subject to PSD review for each regulated pollutant, other than SO_2, for which the sum of all creditable emissions increases and decreases results in a significant net emission increase. Additional prospective and creditable emission reductions sufficient to provide for a less than significant net emission increase at the source may be proposed to avoid PSD review. As shown in Table IV-10, a PSD review is not required for PM_{10} and VOC. Emissions of NO_X and CO require a full PSD review. The PSD review for NO_X and CO is presented in Section V.

SECTION V. PSD REVIEW FOR POLLUTANTS NO_X AND CO

A full PSD review consists of the following steps:

1. Determination of Best Available Control Technology (BACT).
2. Analysis of Air Quality Impacts. This analysis includes:
   - Description of dispersion model and procedures
   - Determination of air quality impact significance
   - Determination of pre-construction monitoring requirements
   - Compliance with National Ambient Air Quality Standards (NAAQS)
   - Compliance with available PSD increments
3. Evaluation of Source-related Impacts on Growth, Soils, Vegetation, and Visibility.
4. Evaluation of Class I Area Impacts.

1. Determination of BACT

OAC 252:100-8-1.1 defines BACT as *"...the control technology to be applied for a major source or modification is the best that is available as determined by the Director on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs of alternate control systems."*

A BACT analysis is required to assess the appropriate level of control for each new or physically modified emissions unit for each pollutant that exceeds the applicable PSD SER. As shown in Section IV, only net emissions of NO_X and CO exceed the PSD SER.

The U.S. EPA has stated its preference for a "top-down" approach for determining BACT and that is the methodology used for this permit review. After determining whether any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the available control technologies, including the most stringent control technology, for a similar or identical source or source category. If any of the control technologies are technically infeasible for the emission unit in question, that control technology is eliminated from consideration. The remaining control technologies are then ranked by effectiveness and evaluated based on energy, environmental, and economic impacts beginning with the most stringent remaining technology. If it can be shown that this level of control should not be selected based on energy, environmental, or economic impacts, then the next most stringent level of control is evaluated. This process continues until the BACT level under consideration cannot be eliminated by any energy, environmental, or economic concerns. The five basic steps of a top-down BACT review are summarized as follows:

Step 1. Identify Available Control Technologies
Step 2. Eliminate Technically Infeasible Options
Step 3. Rank remaining Control Technologies by Control Effectiveness
Step 4. Evaluation of Remaining Control Technologies Based on Energy, Environmental, and Economic impacts

Step 5. Select BACT and Document the Selection as BACT

The U.S. EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those that provide the maximum degree of emissions reduction. Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of energy, environmental, and economic impacts.

The new or modified NO_X and/or CO emission sources for this project are all combustion sources: new process heaters NH-1, NH-3, NH-4, and NH-5 and leased boilers TB-1, TB-2, and TB-3.

Potentially applicable emission control technologies were identified by researching the U.S. EPA control technology database, technical literature, and control equipment vendor information and by using process knowledge and engineering experience. The RACT/BACT/LAER Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies that have been approved in PSD permits as BACT for numerous types of process units. Process units in the database are grouped into categories by industry. Additional sources of potentially applicable emission control technologies include the California Air Resource Board (CARB) BACT determinations database, the proposed Arizona Clean Fuels, LLC greenfield refinery, and the proposed Hyperion greenfield refinery in South Dakota. These sources were reviewed in order to supplement the RBLC search results.

A. BACT Analysis for Process Heaters & Boilers

Emissions of NO_X

Step 1. Identify Available Control Technologies

Table V-1 is a list of control technologies that were identified for controlling NO_X emissions from process heaters and boilers.

Table V-1. Control Technologies for Emissions of NO_X

NO_X Control Technologies
EM_X™/$SCONO_X$
Combined Ultra Low NO_X Burners (ULNB)/Selective Catalytic Reduction (SCR)
Non-Selective Catalytic Reduction (NSCR)
Selective Non-Catalytic Reduction (SNCR)
Ultra Low NO_X Burners (ULNB)
Low NO_X Burners (LNB)

Step 2. Eliminate Technically Infeasible Options
EM_X™/$SCONO_X$

The EM_X™ catalyst is the latest generation of $SCONO_X$ technology. EM_X™ is a multi-pollutant catalyst that does not require ammonia. While this technology has been demonstrated on units firing pipeline quality natural gas, there is no practical experience with operating on flue gas streams from refinery gas-fired equipment. At this time, EM_X™ is not being used in any commercial refinery situation with equipment using a sulfur-bearing fuel gas stream such as refinery fuel gas because SO_X will contaminate the catalyst and reduce efficiency over time. Additionally, the mechanical complexity of EM_X™ increases in rough proportion to the heat duty rating of the unit. For larger commercial scale units, a large number of mechanical dampers must operate reliably every several minutes under hot and corrosive conditions to divert the flow of flue gas and regenerating hydrogen gas through segments of the catalyst beds. The challenge presented by this demanding design feature is aggravated by the fact that refinery fuel gas combustion products have a higher potential corrosive acid concentration than natural gas combustion products.

The specified EM_X™ catalyst operating temperature range of 300 to 700°F is also a practical limitation for use with refinery process heaters. The typical exhaust temperature range is significantly higher for refinery process heaters and boilers. The EM_X™ catalyst technology is not usable unless the tolerated temperature range is increased or the exhaust temperature of the heaters is controlled.

EM_X™ also creates an increase in system pressure drop that results in a substantial operating cost penalty. It is estimated that the net power incremental requirement due to higher catalyst bed pressure drop is about 1.8 times that associated with a comparable SCR system.

Because of the lack of commercial refinery experience, the catalyst's sensitivity to sulfur compounds, and mechanical limitations, EM_X™ is deemed to be technically infeasible for the refinery process heaters. However, because these issues are not present in the leased boiler application, this technology is technically feasible for the leased boilers.

Non-Selective Catalytic Reduction (NSCR)

NSCR is a flue gas treatment technology that is similar to the catalytic controls on modern automobiles. Precious metal catalysts, such as platinum, are used to promote reactions that reduce most nitrogen oxides (NO) in the exhaust gases to molecular nitrogen (N_2). Likewise, the catalyst will simultaneously convert over 98% of the NO_X and CO and most of the unburned HC emissions according to the NSCR [unbalanced] reactions below:

$$CO + \tfrac{1}{2} O2 \rightarrow CO_2$$
$$NO_X + CO \rightarrow CO_2 + N_2$$
$$H_2 + \tfrac{1}{2} O_2 \rightarrow H_2O$$
$$HC + O_2 \rightarrow H_2O + CO_2$$
$$NO_X + H_2 \rightarrow H_2O + N_2$$

These reactions can only occur in this manner when the oxygen content of the exhaust is controlled to less than 1% vol. (typically about 0.5% vol.), which is accomplished by attaching an air/fuel controller (lambda sensor) to maintain the chemically correct (or stoichiometric) air/fuel ratio (AFR), such that all the fuel and oxygen in the mixture are consumed on combustion, and is typically referred to as a rich-burn or stoichiometric operation. The formulas above show that CO must be present in the exhaust gas in order for the NO_X to be reduced to N_2. The refinery heaters and leased boilers operate in a lean burn (i.e., oxygen rich) environment where the O_2 content is substantially greater than 1% vol. There would not be enough CO present in the exhaust stream to effectively react the NO_X to N_2. Therefore, NSCR is deemed technically infeasible for both the refinery heaters and the leased boilers.

All of the remaining listed technologies are considered feasible for control of NO_X emissions from heaters and boilers.

Step 3. Rank Remaining Control Technologies by Control Effectiveness.

The remaining options are ranked in Table V-2 based on effectiveness.

Table V-2. Remaining NO_X Control Technologies Ranked by Effectiveness

Control Technology	Control Efficiency (%) (1)	Calculated Efficiency (%) (2)	Approximate Emissions (lb/MMBtu)
EM_X™/$SCONO_X$ (Leased Boilers Only)	90 – 98	90	0.0085
ULNB/SCR or SCR	70 - 90	70	0.03 - 0.02
ULNB	70 - 90	60	0.04 - 0.03 (3)
SNCR	30 - 50	0	0.09 - 0.04
LNB	< 40	Base Case	0.08 (4)

1. Typical range of efficiencies from literature such as U.S. EPA “Petroleum Refinery Tier 2 BACT Analysis Final Report” Table 3-2 BACT Control Hierarchy for NO_X with uncontrolled burners as the base case, and Chemical Engineering Progress, *Select the Right NO_X Control Technology*, New York, NY: American Institute of Chemical Engineers, January 1994, P.34, Table 2.
2. Approximate calculated efficiencies using midrange of control and Low NO_X Burners as the base case.
3. Based on review of RACT/BACT/LAER Clearinghouse for heaters less than 250 MMBtu/hr.
4. Based on vendor-provided Low NO_X Burner emission factor.

<u>ULNB/SCR or SCR</u>

The combination of ULNB with SCR has recently been used in some applications of combined cycle turbines and large heaters and boilers. By combining these technologies, it is possible to achieve NO_X removal efficiency of at least 90% from a base case of LNB alone. The use of just SCR is also an option. Since both require installation and operation of an SCR system, they are considered together.

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 SCR process requires a reactor vessel, a catalyst, and an ammonia storage and injection system. The SCR system requires ammonia, a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP). The presence of the catalyst effectively reduces the ideal reaction temperature for NO_X reduction to between 520 and 720 degrees Kelvin (K) (approximately 475 and 850°F) and increases the surface area available for NO_X reduction. As a post-combustion process, the SCR system is usually installed to receive flue gas after it has left the combustion chamber. The exact location of the SCR reactor will vary depending upon what other type of pollution control systems are also present.

The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, the type of catalyst, and the presence of catalyst poisons, such as particulate matter and SO_2. SCR units typically achieve 70 to 90% NO_X reduction with an ammonia exhaust concentration (ammonia slip) of 5 to 10 parts per million by volume on a dry basis (ppmvd) at 15% oxygen. Additional environmental concerns are caused by the formation of secondary particulate from the ammonia reagent. The phenomenon can be more pronounced as ammonia slip increases.

<u>SNCR</u>

SNCR describes a process by which NO_X is reduced to molecular nitrogen (N_2) by injecting an ammonia or urea ($CO(NH_2)_2$) spray into the post-combustion area of the unit. Typically, injection nozzles are located in the upper area of the furnace and convective passes. Once injected, the urea or ammonia decomposes into NH_3 or NH_2 free radicals, reacts with NO_X molecules, and reduces to nitrogen and water. These reactions are endothermic and use the heat of the burners as energy to drive the reduction reaction. The ammonia and urea reduction equations are shown below.

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

For urea: $4NO + 2\ CO(NH_2)_2 + O_2 \rightarrow 4N_2 + 2CO_2 + 4\ H_2O$

Both ammonia and urea have been successfully employed as reagents in SNCR systems and have certain advantages and disadvantages. Ammonia is less expensive than urea and results in substantially less operating costs at comparable levels of effectiveness. Urea, however, is able to penetrate further into flue gas streams, making it more effective in larger scale burners and combustion units with high exhaust flow rates. In addition, ammonia is a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP). SNCR is considered a selective chemical process because, under a specific temperature range, the reduction reactions described above are favored over reactions with other flue gas components. Although other operating parameters such as residence time and oxygen availability can significantly affect performance, temperature remains one of the most prominent factors affecting SNCR performance.

The SNCR process requires the installation of reagent storage facilities, a system capable of metering and diluting the stock reagent into the appropriate solution, and an atomization/injection system at the appropriate locations in the combustion unit. The reagent solution is typically injected along the post-combustion section of the combustion unit. Injection sites around the unit must be optimized for reagent effectiveness and must balance residence time with flue gas stream temperature.

For ammonia, the optimum reaction temperature range is 1,600 to 2,000°F, while optimum urea reaction temperature ranges are marginally higher at 1,650 to 2,100°F. Although the overall chemistry is identical to that used in the SCR system, the absence of a catalyst results in several differences. The un-catalyzed reaction requires a higher reaction temperature and is not as effective.

ULNB

There are several designs of 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.

Modern ULNB technology is available at NO_X emissions rate of 0.04 to 0.03 lb/MMBtu for the size range of heaters and boilers in the Refinery Upgrade Projects.

LNB

The use of LNB is considered as a baseline control technology since most all modern heaters and boilers in the refining industry are equipped with LNB. A NO_X emission rate of 0.08 lb/MMBtu is typically considered an average emission rate for LNB technology.

Step 4. Evaluation of Remaining Control Technologies Based on Energy, Environmental, and Economic Impacts

EM_X™/$SCONO_X$

As mentioned above, EM_X™ is a multi-pollutant catalyst that significantly reduces NO_X, SO_X, CO, VOC and PM emissions. EM_X™ has been installed on large natural gas-fired sources that require Lowest Achievable Emission Rate (LAER) controls. EM_X™ does not require ammonia, so it reduces particulate and has less environmental impact than comparative SCR systems.

Although EM_X™ has the potential for successful NO_X reduction, the cost for an EM_X™ control system on each of the leased boilers (TB-1, TB-2, and TB-3) is estimated at approximately $21,200 per ton of NO_X removed. This cost is considered to be economically infeasible for BACT. Due to high cost, EM_X™ is not selected as BACT for control of NO_X emissions from the leased boilers.

ULNB/SCR or SCR

The applicant evaluated the cost effectiveness of an SCR system for the heaters and boilers. The baseline for the tons of NO_X controlled by the SCR system is LNB with NO_X emissions of 0.08 lb/MMBtu for the process heaters and 0.049 lbs/MMBtu for the leased boilers. The controlled emissions for SCR were taken as 0.022 lb/MMBtu for the process heaters and 0.013 lbs/MMBtu for the leased boilers. The cost to install and operate an SCR system is approximately $10,500 per ton of NO_X controlled for heater NH-1 and $32,000 per ton of NO_X controlled for the leased boilers. If the same costs for the SCR system are applied to a ULNB/SCR combination with a controlled rate of 0.0085 lb/MMBtu, the cost to install and operate an ULNB/SCR system (assuming no additional cost for the ULNB) would be approximately $9,000 per ton of NO_X controlled for NH-1 and $28,000 per ton of NO_X controlled for the leased boilers.

Based on the costs associated with the ULNB/SCR system or SCR system and the associated environmental impacts resulting from ammonia slip, ULNB/SCR and SCR are eliminated from further consideration.

SNCR

The NO_X control level for SNCR is expected to be either equal to or slightly lower than for modern ULNB. However, the applicant evaluated the cost effectiveness for an SNCR system for the heaters and boilers. The baseline for the tons of NO_X controlled by the SNCR system is LNB with NO_X emissions of 0.08 lb/MMBtu for the process heaters and 0.049 lbs/MMBtu for the leased boilers. The controlled emissions for SNCR were taken as 0.04 lb/MMBtu for LNB/SCR for the process heaters and 0.025 lbs/MMBtu for the leased boilers. The cost to install and operate an SNCR system is approximately $11,000 per ton of NO_X removed for heater NH-1 and $24,000 per ton of NO_X controlled for the leased boilers. This cost level is considered to be economically infeasible for BACT. Therefore, SNCR is eliminated from further consideration.

Step 5. Select BACT and Document the Selection as BACT

Since ULNB provides the highest remaining feasible control, BACT has been proposed as ULNB at an emission rate of 0.03 lb/MMBtu for the new process heaters. The leased boilers are existing units and are expected to have a manufacturer's guarantee of 0.036 lb/MMBtu, which is proposed as BACT for the leased boilers.

The RBLC database indicates emissions rates of 0.03 to 0.05 lb/MMBTU for similar sized units using ULNB technology. The RBLC does contain heaters with lower emission rates (i.e., 0.0125 lb/MMBTU), but these heaters utilize SCR controls, are large, and are mainly in nonattainment areas. SCR proved economically infeasible and has adverse energy and environmental impacts given the size and nature of the proposed heaters. Therefore, the proposed ULNB controls are acceptable as BACT.

Emissions of CO

Step 1. Identify Available Control Technologies

The available control technologies identified for the control of CO emissions from process heaters and boilers are presented in Table V-3.

Table V-3. Control Technologies for Emissions of CO

Control Technologies
Regenerative Thermal Oxidation (RTO)
Regenerative Catalytic Oxidation (RCO)
ULNB
Good Combustion Practice

Regenerative Thermal Oxidation

Thermal oxidizers combine temperature, time, and turbulence to achieve complete combustion. Thermal oxidizers are equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO. The waste gas is passed through burners, where the gas is heated above its ignition temperature. Thermal oxidation requires raising the flue gas temperature to 1,300 to 2,000°F in order to complete the CO oxidation. Depending on specific furnace and thermal oxidizer operational parameters (fuel gas heating value, excess oxygen in the flue gas, flue gas temperature, and oxidizer temperature) raising the flue gas temperature can require an additional heat input of 10 to 25% above the process heater heat input. Also, depending on the design of the thermal oxidizer, emissions of NO_X, SO_2, and PM_{10} can be 10 to 25% higher than emissions without a thermal oxidizer.

Regenerative Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and at a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 feet per second (fps) to 30 fps. Catalytic oxidizers typically operate at 650 to 1,000°F. This can require from 0 to 10% in additional fuel and a resulting similar increase in other pollutant emissions.

Catalytic oxidizers cannot be used on waste gas streams containing significant amounts of particulate matter as the particulate deposits foul the catalyst and prohibit oxidation. High temperatures can also accelerate catalyst deactivation; however, that is normally not a concern with flue gas from process heaters and boilers.

ULNB

ULNB technology has developed to provide increasing lower levels of NO_X emissions. However, when operated using good combustion practices, ULNB can also provide significant reductions in CO emissions, with an emissions rate of 0.04 lb/MMBtu considered typical.

Good Combustion Practice

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air, temperature, residence time, and mixing are incorporated in the combustion design and operation, CO emissions are minimized. The design of modern, efficient combustion equipment is such that there is adequate turbulence in the flue gas to ensure good mixing, a high temperature zone (greater than 1,800°F) to complete burnout, and sufficient residence time at the high temperature (one to two seconds).

Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions.

Step 2. Eliminate Technically Infeasible Options

A search of the RBLC database indicated that thermal and catalytic oxidation has rarely been applied to process heaters or boilers. Typically, higher concentrations of CO in the pollutant stream are needed to justify the use of thermal oxidation and catalytic oxidation. However, neither control option can be eliminated as technically infeasible. Therefore, all of the technologies mentioned above will be examined for energy, environmental, and economic impacts.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

The remaining options are ranked in Table V-4 based on effectiveness.

Table V-4. Remaining CO Control Technologies Ranked by Effectiveness

Control Technology	Range of CO Reduction, %	Typical CO Reduction, %	Typical Emission Level, lb/MMBtu
Regenerative Thermal Oxidation	75 - 95	90	0.008
Regenerative Catalytic Oxidation	75 - 95	90	0.008
ULNB	25 - 75	50	0.04
Good Combustion Practice	Base Case	Base Case	0.08

Step 4. Evaluation of Remaining Control Technologies Based on Energy, Environmental, and Economic Impacts

Regenerative Thermal Oxidation

Installation costs and operating costs (mostly from the 10 to 25% increase in fuel consumption) are significant. The applicant evaluated the costs to install and operate a regenerative thermal oxidizer for the heaters and boilers. Annual costs were calculated to be approximately $45,000 per ton of CO controlled for heater NH-1 and $29,000 per ton of CO controlled for the leased boilers. In addition, the use of a thermal oxidizer can significantly increase the emissions of NO_X from the heaters and boilers.

A search of the RBLC and recently issued permits in attainment areas indicated that thermal oxidation has not been selected as BACT for control of CO. Therefore, based on the additional use of energy, the increase in emissions of other pollutants, the associated costs, and no previous documentation of thermal oxidation as BACT; thermal oxidation is eliminated from further consideration.

Regenerative Catalytic Oxidation

The applicant evaluated the costs to install and operate a regenerative catalytic oxidizer for the heaters and boilers. Annual costs were calculated to be approximately $23,000 per ton of CO controlled for heater NH-1 and $14,500 per ton of CO controlled for the leased boilers. These cost levels are considered to be economically infeasible for BACT. Also, an environmental consideration is the disposal of spent catalyst, which is considered a hazardous material.

A search of the RBLC and recently issued permits in attainment areas indicated that catalytic oxidation was rarely selected as BACT. Therefore, based on the additional use of energy, the possible increase in emissions of other pollutants, the associated costs, and no previous documentation of catalytic oxidation as BACT; catalytic oxidation is eliminated from consideration as BACT for this project.

ULNB

A review of the RBLC database indicated that use of ULNB was selected as BACT for a number of PSD permits. These determinations were usually made on the basis that use of ULNB was BACT for NO_X and would also be selected as BACT for CO. As the ULNB technology has achieved lower emissions of NO_X, the burners have also provided lower emissions of CO. Recent BACT determinations have shown CO emissions ranging from 0.02 to 0.06 lb/MMBtu, with 0.04 lb/MMBtu as the most typical emission level.

Good Combustion Practice

Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. There is no increased energy requirement or increased pollutants with good combustion practice. The RBLC database lists this option as the most prevalent form of BACT for controlling CO emissions from process heaters and boilers. Modern heater and burner designs combined with good combustion practice by the operator can produce CO emissions as low as 0.08 lb/MMBtu for standard burners and as low as 0.02 lb/MMBtu for ULNB.

Step 5. Select BACT and Document the Selection as BACT

All the new process heaters and boilers for this project will be equipped with ULNB. The applicant has proposed the use of ULNB along with Good Combustion Practice as BACT at an emissions rate of 0.04 lb/MMBtu. This is acceptable to AQD as BACT.

The following regulations contained within 40 CFR 60 were reviewed with regards to the new process heaters:

- Subpart J – Standards of Performance for Petroleum Refineries
- Proposed Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

When the currently-stayed provisions of NSPS Subpart Ja come into effect, the Refinery will comply with its applicable limits. One of the currently-stayed provisions of NSPS Subpart Ja includes a NO_X emission limit for process heaters with rated capacities greater than 40 MMBTU/Hr of 40 ppm NO_X by volume, dry basis corrected to 0% excess air, on a 24-hour rolling average basis, which is approximately equivalent to 0.042 lbs NO_X/MMBTU. The NO_X emission limit proposed for the new heaters is more stringent, and therefore compliant with the currently-stayed NSPS Subpart Ja limit. Subpart Ja does not include CO limits for fuel gas combustion devices such as the new heaters. NSPS Subpart J does not include NO_X or CO emission limits for fuel gas combustion devices. In addition, the regulations are not applicable to these heaters because of their date of manufacture. Lastly, there are no currently applicable MACT standards with limits for NO_X or CO.

An initial compliance test will be conducted on the heaters to demonstrate compliance with the proposed NO_X and CO emission limits. In addition, the ULNB design and proposed work practices will comply with the applicable regulations. Because of their size (i.e. rated heating capacity ≥ 100 MMBTU/Hr), the Refinery will install NO_X and O_2 continuous emissions monitoring system (CEMS) on new heaters NH-1 and NH-4 as per the requirements of the non-stayed provisions of NSPS Subpart Ja. The O_2 CEMS will also serve to demonstrate that the two heaters are operated using good combustion practices. For new heaters NH-3 and NH-5, whose rated heating capacities are less than 100 MMBTU/Hr and greater than 40 MMBTU/Hr, the Refinery will use fuel gas meters and NOx emission factors derived from the initial compliance tests to develop a PEMS to demonstrate continuous compliance with the proposed emission rates. In addition, biennial stack tests will be conducted for heaters NH-3 and NH-5, also as per the requirements of the non-stayed provisions of NSPS Subpart Ja. Given the CEMS and PEMS, compliance with the proposed NO_X and CO emission limits will be determined on a continuous basis.

The following regulations contained within 40 CFR 60 were reviewed with regards to the leased boilers:

- Subpart Dc – Small Industrial-Commercial-Institutional Steam Generating Units that Commenced Construction After June 9, 1989
- Subpart J – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and Before May 14, 2007

Subpart Dc does not include NO_X or CO emission limits for gas-fired boilers. The only requirements for these boilers are initial notification and recordkeeping of the fuel combusted during each calendar month.

Subpart J specifies a limit of 0.10 gr/dscf for H_2S (160 ppmv @ 60°F) content in fuel gas burned in any fuel gas combustion device and requires that a continuous monitoring device to measure fuel gas H_2S concentration be installed, operated and maintained. The leased boilers will comply with Subpart J by firing only pipeline quality natural gas.

Subpart J does not contain NO_X or CO emission limits for fuel gas combustion devices. Subpart J does include testing, reporting, and recordkeeping requirements. There are no currently applicable MACT standards with limits for NO_X or CO for the leased boilers.

The Refinery will use fuel gas meters and emission factors derived from the initial compliance tests to develop a PEMS to demonstrate continuous compliance with the proposed emission rates.

Analysis of Air Quality Impacts

An air impact analysis is required for a major modification of an existing PSD major source that results in a significant net emissions increase for any pollutant. As previously shown, this project resulted in a significant net emissions increase for NO_X and CO.

A description of the dispersion model and procedures used for the model is provided in the ambient air impact analysis. The analysis also includes a determination of air impact significance based on Modeling Significance Level (MSL), determination of any pre-application monitoring requirements based on Monitoring De Minimis Concentrations, compliance with the NAAQS (if required), and compliance with available PSD increments (if required). An air impact analysis for emissions of NO_X and CO follows.

Description of dispersion model and procedures

Modeling Methodology

AERMOD PRIME (Version 07026) was used for this analysis. AERMOD is a refined, steady-state, multiple source Gaussian dispersion model and is the preferred model to use for industrial sources in this type of analysis. The modeling analysis was performed using the regulatory default models settings, which include stack heights adjusted for stack-tip downwash and missing data processing.

Land Use

The meteorological data was provided by the Oklahoma DEQ for Blackwell, OK. This data set was prepared by the state and provided to Trinity in a model-ready format. Table V-5 summarizes the land-use/micromet parameters, i.e. Albedo, Bowen ratio, and surface roughness used in the DEQ data set.

Table V-5. AERMET Land-Use Parameters

Parameters	Winter	Spring	Summer	Autumn
	Dec-Jan-Feb	Mar-Apr-May	Jun-Jul-Aug	Sep-Oct-Nov
Albedo Values	0.18	0.15	0.19	0.19
Bowen Ratio Average Values	0.74	0.035	1.45	1.45
Surface Roughness Values	0.017	0.035	0.145	0.145

Terrain

Building elevations were obtained from engineering elevation drawings. Source heights were obtained from ConocoPhillips. The receptor terrain elevations entered into the model were the highest elevations extracted from USGS 7.5-minute digital elevation model (DEM) data of the area surrounding the ConocoPhillips Ponca City Refinery. DEM is a digital file consisting of terrain elevations for ground positions at regularly spaced intervals (every 7.5 minutes). For each receptor elevation, the maximum terrain elevation associated with the four DEM points surrounding the receptor was selected.

Building Wake Effects (Downwash)

In order to account for building wake effects, direction-specific building dimensions used as input to the model were calculated using the *BREEZE®-AIR* software. This software incorporates the algorithms of the U.S. EPA-sanctioned Building Profile Input Program (BPIP), which is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document, and other related documents.

Meteorological Data

The meteorological data was provided ready for use by the Oklahoma DEQ. It had been provided to the Air Quality Division of the ODEQ as a courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University and The University of Oklahoma. The model runs were performed using 2001-2005 Blackwell meteorological data set using ISH data from Ponca City Municipal Airport (KPNC) and upper air (UA) data from Norman, OK (OUN - 3948).

Inventory Sources

In the event that modeling significance levels (MSLs) are exceeded, a full impact analysis must be performed. First, the radius of impact (ROI) for each pollutant and averaging period that is significant must be determined. As described in 40 CFR 51, Appendix W, the ROI is defined as the distance to the facility from the furthest significant receptor. Then, an inventory of NAAQS and PSD increment-consuming sources located within this ROI plus 50 km must be developed. The Oklahoma DEQ maintains a database of NAAQS and PSD increment consuming sources.

Inventory of PSD Increment Consuming Emission Sources

- Source listing for all existing non-ConocoPhillips NO_X PSD Increment Consuming sources was provided by the DEQ's ARIES system from requests for this project.
- Source listing for all existing ConocoPhillips PSD Increment Consuming sources was provided by the DEQ's ARIES system from a previous inventory request conducted in mid-2007 for the Wichita Mountains NWR. Verification and addition of select sources was performed using historical EI data.
- Per Table C-5 in the U.S. EPA's NSR Workshop Manual, source emissions for background (i.e., non-modified inventory sources) are allowed to account for actual operating factors when modeling over an annual time period. 2005-2006 EI data was used for all existing ConocoPhillips PSD Increment Consuming Sources when determining their NO_X emissions.

Inventory of NAAQS Emission Sources

- NO_X

- Multiple files with listings of NO_X NAAQS sources in the ROI were provided by the DEQ's ARIES system. All ARIES data files were combined in a single NAAQS emission source inventory.
- Similar to the PSD Increment Consuming source inventory, 2005-2006 EI data was used for all ConocoPhillips NAAQS sources when determining their NOx emissions.
- Per DEQ's request, all sources provided by the DEQ were modeled, regardless if they screened out using either the 20D or 10D rule.

▪ CO
  - The same source inventory was used as in the NOx NAAQS analysis.
  - For permitted ConocoPhillips sources permit allowable emission rates were used to calculate the CO model emission rates. For the unpermitted ConocoPhillips sources the average of the actual emissions for CY 2005 and CY 2006 was used. The emissions data was obtained from the 2005 and 2006 Conoco emission inventories.
  - Per DEQ's request, all sources provided by DEQ were modeled, regardless if they screened out using either the 20D or 10D rule.

Receptor Grids

Ground-level concentrations were calculated for receptors located on three Cartesian grids covering a region that extends 10 km from all edges of the facility fence line. The grids were defined as follows:

- A Fence Line Grid containing 50 meter-spaced receptors located along the facility fence line;
- A Fine Grid containing 100 meter-spaced receptors, extending approximately 1.0 km from the fence line, exclusive of the Fence Line grid;
- A Medium Grid containing 500 meter-spaced receptors, extending approximately 5.0 km from the fence line; and
- A Coarse Grid containing 1,000 meter-spaced receptors, extending approximately 10 km from the fence line.

Per DEQ's request, the full receptor grid was modeled in the full impact analysis, instead of modeling only the receptors at which the NO_X significance level was exceeded.

Stack Parameters

Stack parameters were obtained from several different sources. For permitted sources, the stack parameters contained in the permit memorandum were used. Stack parameters for new and un-permitted sources were obtained from current design estimates. More detailed information, including stack locations, are available in the permit application and in the air dispersion modeling CD provided by the applicant.

Determination of air quality impact significance

Significance Analysis

In the significance analysis, the net annual emissions increase from the project is modeled for each pollutant. The maximum-modeled ground-level concentrations are then compared to the corresponding modeling significance levels (MSLs). The U.S. EPA requires that a full impact analysis be conducted if the project emissions result in maximum predicted concentrations exceeding the MSLs (i.e., significant impacts).

A significance analysis for NO_2 and CO was completed to determine if the net emissions increase would have a significant impact upon the area surrounding the facility, i.e. if the modeled pollution concentrations would exceeded their respective MSL. The significance analysis determines whether pre-construction monitoring is required, if the facility can forego further analyses for a particular pollutant, and defines the radius of impact (ROI) within which a full impact analysis (if required) should be conducted. In such situations, the significance analysis also indicates the locations (receptors) and time periods that must be examined in the full impact analysis.

Total nitrogen oxide (NO_X) emissions were modeled for comparison to the NO_2 MSL. Then, the U.S. EPA's Ambient Ratio Method (ARM) was used to convert predicted NO_X impacts to NO_2.

Results from the air dispersion significance modeling analysis are summarized in Table V-6.

Table V-6. Significance Analysis Results

Year	NO_X	NO_2	CO		SO_2		
	Annual	Annual	8-Hr	1-Hr	Annual	24-Hr	3-Hr
2001	17.59	13.19	493.22	864.40	0.30	1.74	4.61
2002	13.43	10.07	491.77	764.93	0.33	1.90	4.22
2003	14.47	10.85	565.65	788.19	0.26	1.82	4.32
2004	14.03	10.52	454.03	758.61	0.29	1.92	3.95
2005	14.93	11.20	453.16	773.27	0.33	1.73	4.03
Maximum	**-**	**13.19**	**565.65**	**864.40**	**0.33**	**1.92**	**4.61**
Monitoring De Minimis	-	14	575	-	-	13	-
MSL	-	1	500	2,000	1	5	25
Full Impact Analysis Required?		**Yes**	**Yes**	**No**	**No**	**No**	**No**

As seen from Table V-6, NO_2 and CO impacts exceed the annual average MSL. An examination of the model results indicates that the significant receptor located furthest from the facility is approximately 1.7 km for NO_X and 0.1 km for CO from the center of the facility A radius of 60 km was used in determining the nearby source inventory.

A 10D analysis was then used to screen sources out of the ARIES data source inventory. Any source with combined potential emissions [in TPY] less than 10 times the distance to the ConocoPhillips facility [in km] was removed from the nearby source list.

Determination of pre-construction monitoring requirements

The permitting agency has the authority to exempt a project from pre-construction monitoring if the concentrations modeled in the significance analysis are less than monitoring *de minimis* concentrations. As shown in Table V-7, the modeled concentrations are less then the *de minimis* concentrations and no pre-construction monitoring was required.

Table V-7. *De minimis* Analysis Results

Year	NO_X	NO_2	CO		SO_2		
	Annual	Annual	8-Hr	1-Hr	Annual	24-Hr	3-Hr
Maximum	**-**	**13.19**	**565.65**	**864.40**	**0.33**	**1.92**	**4.61**
Monitoring De Minimis	-	14	575	-	-	13	-

Compliance with NAAQS

Full Impact Analysis

When a pollutant exceeds its MSL, a full impact analysis is performed to determine compliance with NAAQS and PSD increment standards. The first step in the full impact analysis is to determine the radius of significant impact (ROI). For each pollutant exceeding the MSL, all significance analysis output data files are screened to locate the furthest receptor from the facility whose modeled concentration exceeds the corresponding MSL. Then, an inventory of off-property sources is obtained from DEQ using the ROI determined. Inventory sources included in the full impact analysis are all sources that have the potential to contribute significantly within the facility's ROI plus 50 km. The 20D rule is applied to all sources within the ROI, so all sources whose emissions (in tons per year) are greater than 20 times the distance (in km) are included in the full impact analysis.

NAAQS Analysis

To complete the NAAQS analysis, the total emissions from the facility were modeled simultaneously with the emissions from the NAAQS sources identified in the inventory provided by the DEQ. The background concentrations for the annual averaging periods are added to the modeled concentration for comparison with the NAAQS. The first highest concentration is compared to the corresponding NAAQS standard to determine if the emissions from the proposed project will cause or contribute to a violation of the NAAQS. As shown in Tables V-8 and V-8a, the NAAQS is not exceeded for NO_2 or for CO.

Table V-8. NO_X NAAQS Analysis Results

Year	Modeled NO_X Annual ($\mu g/m^3$)	Modeled $NO_2^{(1)}$ Annual ($\mu g/m^3$)	Background $NO_2^{(2)}$ Annual Average ($\mu g/m^3$)	Total NO_2 Annual ($\mu g/m^3$)
2001	94.70	71.03	10.51	81.54
2002	92.77	69.57	10.51	80.09
2003	80.49	60.37	10.51	70.88
2004	93.83	70.37	10.51	80.88
2005	86.62	64.97	10.51	75.48
Maximum	**-**	**-**	**-**	**81.54**
NAAQS	**-**	**-**	**-**	**100**

1. Total nitrogen oxide (NO_X) emissions were modeled for comparison to the NO_2 MSL. Then, the U.S. EPA's Ambient Ratio Method (ARM) was used to convert predicted NO_X impacts to NO_2.
2. Average of 2003 and 2004 in Ponca City [Site ID 400819003], the most recent NO_2 monitoring done in any county.

Table V-8a. CO NAAQS Analysis Results

Year	Modeled CO 8-Hr ($\mu g/m^3$)	Background CO 8-Hr(1) ($\mu g/m^3$)	Total CO 8-Hr ($\mu g/m^3$)
2001	2,202	2,508	4,710
2002	2,127	2,508	4,635
2003	3,067	2,508	5,575
2004	2,085	2,508	4,593
2005	2,547	2,508	5,055
Maximum	**-**	**-**	**5,575**
NAAQS Increment	**-**	**-**	**10,000**

1. Based on 2007 monitoring data from Oklahoma City [Site ID 401090047]. Monitoring data from the Ponca City site for 2004 was not considered to be representative of background concentration.

Compliance with available PSD increments

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 major source baseline date depends upon the county in which the facility is located and on the pollutant in question. Sources that contribute to emissions increases after the baseline date are obtained from the DEQ, and total facility-wide potential emissions are modeled simultaneously with the PSD Increment inventory sources provided by the DEQ. As shown in Table V-9, the PSD increment for NO_2 is not exceeded.

Table V-9. PSD Increment Analysis Results

Year	**NO_X Annual** ($\mu g/m^3$)	**NO_2 (1) Annual** ($\mu g/m^3$)
2001	21.61	16.21
2002	17.34	13.00
2003	18.45	13.84
2004	17.98	13.48
2005	18.98	14.24
Maximum	**-**	**16.21**
PSD Increment	**-**	**25**

1. Total nitrogen oxide (NO_X) emissions were modeled for comparison to the NO_2 MSL. Then, the U.S. EPA's Ambient Ratio Method (ARM) was used to convert predicted NOx impacts to NO_2.

3. Evaluation of Source-related Impacts on Growth, Soils, Vegetation, and Visibility

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 CO, NO_X, and SO_2 as part of this PSD application. The following are addressed:

- Growth impact analysis
- Soil and vegetation impact analysis
- Visibility impairment impact analysis

Growth Impact Analysis

The elements of a growth impact analysis include a projection of the industrial, commercial, and residential growth that will occur in the area due to the proposed projects, 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 projects. Since there is no significant commercial or industrial growth, negligible growth-related air pollution impacts are expected.

Soil and Vegetation Analysis

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants.

Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

At the levels of CO, NO_X, and SO_2 that occur in urban air, there are no detrimental effects on materials or plants, however human health may be adversely affected at such levels. The NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. The maximum predicted CO, NO_X, and SO_2 pollutant concentrations from the proposed projects are below the NAAQS. Therefore, no significant adverse impact on soil and vegetation due to CO, NO_X, and SO_2 emissions is anticipated from the proposed projects.

Visibility Impact Analysis

The proposed projects are not expected to produce any perceptible visibility impacts in the immediate vicinity of the Refinery. Given the Refinery's limitation on opacity of emissions, and a reasonable expectation that normal operation of the units will result in 0% opacity, no immediate visibility impairment is anticipated.

4. Evaluation of Class I Impacts

The Class I analysis followed current guidelines and methods recommended by the Federal Land Managers (FLMs) for a Class I area impact analysis. As an alternative to the standard Class I analysis, the FLMs are currently preparing new guidance that proposes the use of $Q/D<10$, where Q is equal to the increase in NO_X emissions added to the increase in SO_2 emissions that result from the project and D is the distance from the source to the Class I Area. If Q/D is less than 10, a Class I area impact analysis is not required.

Source Emissions and Parameters

Increases in emissions of NO_X and SO_2 from the projects are summarized in Table V-10.

Table V-10. Calculation of Pollutant Quantity (Q), New and /Modified Units

ID	Description	NO_X	SO_2	Quantity ($NO_X + SO_2$)
		TPY	TPY	TPY
NH-3	New No. 4 CTU Vacuum Heater	5.9	2.4	8.3
NH-4	New No. 4 CTU Crude Heater	16.4	6.6	23.0
NH-5	New No. 1 CTU Tar Stripper Heater	12.9	5.2	18.1
FUG	1CTU/4CTU Components	0.0	0.0	0.0
NH-1	New Naphtha Splitter Reboiler	17.3	6.9	24.2
FUG	Benzene Reduction Components	0.0	0.0	0.0
TB-1	Leased Boiler 1	15.0	0.2	15.2

TB-2	Leased Boiler 2	15.0	0.2	15.2
TB-3	Leased Boiler 3	15.0	0.2	15.2
FUG	5 FCCU/VRU Fug Components	0.0	0.0	0.0
Bender	Bender Replacement	0.0	0.0	0.0
Total		**97.5**	**21.7**	**119.2**

Table V-11 shows the calculation for the Q/D ratio and the distances of Class I areas from the refinery. The modeling previously discussed demonstrated that the Class I significance level for NOx was only exceeded for a distance of 1 to 4 kilometers south of the facility. Therefore the impact at the closest Class I area [252 km] must be less than the Class I significance level. Based on the FLM guidance, no Class I impact analysis is required.

Table V-11. Class I Impact Analysis Results

Class I Area	Quantity (Q, TPY)	Minimum Distance (D, km)	Q/D (TPY/km)	Q/D<10?
Caney Creek	119.2	363.7	0.3	**Yes**
Hercules Glade	119.2	364.2	0.3	**Yes**
Upper Buffalo	119.2	335.1	0.4	**Yes**
Wichita Mountains	119.2	252.7	0.5	**Yes**

SECTION VI. OKLAHOMA AIR POLLUTION CONTROL RULES

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

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

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards. Modeled emissions due to the project, provided in Section V, demonstrate that the facility will not have a significant impact on air quality.

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

OAC 252:100-7 (Permits for Minor Facilities) [Not Applicable]
The 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 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

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

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the construction permit application, or developed from the applicable requirement. The proposed projects are considered physical changes that are considered significant modifications of a Part 70 permit; therefore, a construction permit is required. After construction, the permit requirements for this modification will be incorporated into the facility's Part 70 permit.
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 following the malfunction or release. Within ten (10) working days after the immediate notice is given, the owner or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. In addition, if the owner or operator wishes to be considered for the exemption established in OAC 252:100-9-3.3, a Demonstration of Cause must be submitted within 30 calendar days after the occurrence has ended.

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

OAC 252:100-19 (Particulate Matter) [Applicable]
Section 19-4 regulates emissions of particulate matter (PM) from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Fuel-burning equipment is defined in OAC 252:100-1 as "combustion devices used to convert fuel or wastes to usable heat or power." Thus, the process heaters and leased boilers for this project are subject to the requirements of this subchapter. The most stringent fuel-burning equipment limitation is 0.10 lb/MMBtu. AP-42 (7/98) Table 1.4-2 lists PM emissions for natural gas combustion from heaters and boilers to be 0.0076 lb/MMBtu, which is in compliance. The permit will require that all 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 that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. There is very little possibility of exceeding these 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 originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Under normal operating conditions, this facility has negligible potential to violate this requirement; therefore, it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits emissions of sulfur dioxide from any one existing source or any one new petroleum and natural gas process source subject to OAC 252:100-31-26(a)(1). Ambient air concentration of sulfur dioxide at any given point shall not be greater than 1,300 $\mu g/m^3$ in a 5-minute period of any hour, 1,200 $\mu g/m^3$ for a 1-hour average, 650 $\mu g/m^3$ for a 3-hour average, or 130 $\mu g/m^3$ for a 24-hour average. Part 2 also limits the ambient air impact of hydrogen sulfide emissions from any new or existing source to 0.2 ppm for a 24-hour average (equivalent to 280 $\mu g/m^3$). Compliance with these ambient concentrations requirements is assured with the use of either pipeline grade natural gas or refinery fuel gas meeting the requirements of NSPS Subpart J and NSPS Subpart Ja. These projects do not involve any source with significant emissions of H_2S.
Part 5 limits sulfur dioxide emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBtu heat input averaged over 3 hours. All of the new process heaters and leased boilers for this project will be subject to an NSPS standard for SO_2 emissions of an H_2S concentration limit of no more than 0.1 grains/dscf (162 ppmv at 68^{o}F) in the fuel gas. (which is the current NSPS Subpart J limit. The NSPS Ja limit is also 162 ppmv at 68^{o}F). A limit of 0.1 grains/dscf of H_2S in the fuel gas is equivalent to a maximum SO_2 emission rate of 0.03 lb/MMBtu for the estimated future heating value of the refinery fuel gas.
Part 5 also limits hydrogen sulfide emissions from new petroleum or natural gas process equipment (constructed after July 1, 1972). Removal of hydrogen sulfide in the exhaust stream, or oxidation to sulfur dioxide, is required unless hydrogen sulfide emissions would be less than 0.3 lb/hr for a two-hour average. Hydrogen sulfide emissions shall be reduced by a minimum of 95% of the hydrogen sulfide in the exhaust gas. Direct oxidation of hydrogen sulfide is allowed for units whose emissions would be less than 100 lb/hr of sulfur dioxide for a two-hour average. These projects do not involve any source with significant emissions of H_2S.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBtu/hr to emissions of 0.20 lbs of NO_X per MMBtu, three-hour average. All of the new process heaters for this project will have $ULNO_X$ burners that limit NO_X emissions to

0.03 lb/MMBtu and the leased boilers will have $ULNO_X$ burners that limit NO_X emissions to 0.036 lb/MMBtu. Emissions limitations in the permit will be based on these NO_X specifications; therefore, the heaters and leased boilers will be in compliance with this subpart.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
The project does not involve the installation or modification of any of the following equipment: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit. The facility is not located in, nor impacts, a nonattainment area.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
<u>Part 3</u> requires storage tanks constructed after December 28, 1974 with a capacity of 40,000 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to either be operated as a pressure vessel or be equipped with internal/external floating roofs or vapor recovery devices. No new storage tanks are proposed for these projects.
<u>Part 7</u> requires VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device as approved by the Division Director. These projects may involve new pressure relief devices routed to a flare that is in compliance with the provisions of this section.
<u>Part 7</u> 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.
<u>Part 7</u> 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 are subject to NSPS and are, therefore, exempt from this requirement.
<u>Part 7</u> also regulates VOC/water separators that receive water containing more than 200 gallons per day of VOC. Any new or existing waste water systems at the refinery are subject to NSPS Subpart QQQ, which contains standards more stringent than Part 7.

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

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests.

Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

SECTION VII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
PSD applies to this project. The PSD review is presented in Section V.

NSPS 40 CFR Part 60 [Subparts A, Dc, J, Ja, GGGa, and QQQ are Applicable]
Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected sources, which, for this project, are new process heaters and boilers, and new fugitive equipment. Within 30 days after starting construction of the affected sources, the permittee must notify DEQ that construction has commenced. A notification of the actual date of initial startup of any affected source must 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. The permittee 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 permit will require compliance with the notification requirements set forth in Subpart A.

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a maximum design heat input capacity greater than or equal to 10 MMBtu/hr and less than 100 MMBtu/hr and that commenced construction or modification after June 9, 1989. The leased boilers each has a maximum design heat input capacity of 95 MMBtu/hr and are, therefore, subject to Subpart Dc. For units that combust low sulfur gaseous fuel, the only requirements are initial notification and recordkeeping of the fuel combusted during each calendar month.

Subpart J, Petroleum Refineries. This subpart, which was amended on June 24, 2008, affects the following facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators and fuel gas combustion devices which commenced construction, reconstruction, or modification after June 11, 1973 and on or before May 14, 2007, and any Claus sulfur recovery plant which commenced construction, reconstruction, or modification after October 4, 1976 and on or before May 14, 2007. Subpart J specifies a limit of 0.10 gr/dscf for H_2S (160 ppmv @ 60°F) content in fuel gas burned in any fuel gas combustion device and requires that a continuous monitoring device to measure fuel gas H_2S concentration be installed, operated and maintained. Subpart J also includes testing, reporting, and recordkeeping requirements. The leased boilers will be subject to Subpart J. The new process heaters will not be subject to Subpart J based on date of manufacture.

Subpart Ja, Petroleum Refineries. As approved on June 24, 2008, the provisions of Subpart Ja apply to fluid catalytic cracking units, fluid coking units, delayed coking units, process heaters, other fuel gas combustion devices, and sulfur recovery plants which commence construction, reconstruction or modification after May 14, 2007. Subpart Ja provisions also apply to flares which commence construction, reconstruction, or modification after June 24, 2008. However, on July 28, 2008 (See Federal Register/ Vol. 73, No.145/ Monday, June 28, 2008/ Rules and Regulations) EPA stayed Subpart Ja as a result of incorrect classification of Subpart Ja as a non-major rule under the Congressional Review Act. On September 26, 2008 (See Federal Register/ Vol. 73, No.188/ Friday, September 26, 2008/ Rules and Regulations) EPA issued an additional stay for certain specific provisions of Subpart Ja, including the definition of ‘‘modification’’ (§60.100a(c)), the definition of ‘‘flare’’ (§60.101a) and the fuel gas combustion device sulfur limits as they apply to flares, the flow limit for flare systems, the total reduced sulfur and flow monitoring requirements for flares, and the NOx limit for process heaters (§§ 60.102a(g), 60.107a(d), and 60.107a(e)). Following completion of the stay, new process heaters NH-0001, NH-0003, NH-0004, and NH-0005 will be subject to the final emission limits, requirements, etc. of Subpart Ja. Leased boilers TB-0001, TB-0002, and TB-0003 will not be subject to Subpart Ja based on their date of manufacture. If the rule is subsequently revised by EPA, this applicability discussion will be revisited.

The No. 1 Sustaining, the No. 4 CTU Revamp, the Benzene Reduction, and the Bender Conversion projects will include the addition of pressure relief valves (PRVs) from new equipment to the existing collection header for the Ponca City Refinery (PCR) West Plant/North Plant (WP/NP) Flare Gas Recovery Unit (FGRU). The WP/NP FGRU is considered part of the fuel gas system and is upstream of the WP/NP Flare. The WP/NP FGRU is used to capture gases from process equipment, compress those gases, and direct them to the WP/NP fuel gas system for treatment and use in Refinery fuel gas combustions devices (FGCDs) as fuel gas. The PRVs provide overpressure protection for equipment and do not release gases to the WP/NP FGRU under normal operating conditions. As such, the PRV connections will not increase flow to the WP/NP FGRU under normal operating conditions, and thus will not increase flow or flow capacity to the WP/NP Flare. Hence, in this instance, the WP/NP Flare is not being modified per the Subpart Ja definition. The addition of PRVs to the WP/NP FGRU system does not trigger Ja applicability for the WP/NP Flare because no new piping will be added to the flare as defined under Subpart Ja. In addition, the WP/NP Flare will not be physically altered to increase flow capacity.

Subpart Kb, Volatile Organic Liquids Storage Vessels. This subpart affects VOL storage vessels (including petroleum liquids storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984, and which have a capacity of 19,813 gallons (75 cubic meters) or more. There are no new storage tanks proposed for these projects.

Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Subpart GGGa 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, reconstruction, or modification after November 7, 2006 and which is located within a process unit in a petroleum refinery. On June 2, 2008 (See Federal Register/ Vol. 73, No.106/ Monday, June 2, 2008/ Rules and Regulations) EPA stayed the definition of "process unit" included in §60.590[a] and instructed owners and operators to use the following definition; "process unit means 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 components installed as part of the No. 1 CTU Sustaining Project, the No. 4 CTU Revamp Project, the Benzene Reduction project and the Bender Conversion to Merox project, and their associated process units, which are the No. 1 CTU, the No. 4 CTU, the No. 2 Isom Unit, the Reformate Splitter, the Pressure Swing Absorber (PSA) unit, and the Bender unit, are subject to this subpart. The components will be incorporated into the facility's existing LDAR program. The new components installed as part of the Leased Boilers project are not subject to this subpart because the equipment will not be in VOC service because they will be fired using purchased natural gas which is not a VOC.

Subpart QQQ, VOC Emissions from Petroleum Refinery Wastewater Systems. This subpart affects refinery wastewater systems for which construction, reconstruction, or modification commenced after May 4, 1987. This project will involve physical changes to individual drain systems in the form of new process drains and junction boxes. New drains installed as part of this project must be equipped with water seal controls and the applicant must comply with the monitoring, testing, recordkeeping, and reporting requirements of Subpart QQQ.

NESHAP 40 CFR Part 61 [Subpart FF is Applicable]

There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride, except for benzene.

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 that are intended to operate in benzene service, which is defined as having more than 10% benzene by weight. The benzene concentration for each affected unit for this project will be less than 10% by weight and is not intended to operate in benzene service. Therefore, Subpart J is not applicable to this 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. The benzene concentration for waste streams in each affected individual drain system is expected to be less than 10 ppmw for this project. Therefore, in accordance with 40 CFR 61.342(c)(2), the control requirements in this subpart are not applicable to these drain systems. However, the permittee must demonstrate initially and, thereafter, at least once per year that the flow-weighted annual average benzene concentration for the waste stream is less than 10 ppmw as determined by the procedures specified in 40 CRF 61.355(c)(2), knowledge of the waste, or 40 CRF 61.355(c)(3) protocol testing. Records of such determinations must be kept in accordance with 40 CFR

61.356.

NESHAP 40 CFR Part 63 [Subpart CC is Applicable]
Subpart CC, Petroleum Refineries (Refinery MACT I). 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 emit 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 wastewater streams and equipment leak components. Any new wastewater streams for this project are subject to this subpart. New valves, pumps, and associated components resulting from the project may be in organic HAP service and would be subject to the LDAR provisions of Subpart CC.

Subpart UUU, Petroleum Refineries – Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Plants (Refinery MACT II). This subpart affects the following:

- Process vents on each catalytic cracking unit that is associated with regeneration of the catalyst.
- Process vents on each catalytic reforming unit that is associated with regeneration of the catalyst.
- Process vents that vent from a Claus or other type of sulfur recovery plant unit or the tail gas treatment unit.

This subpart does not apply to a gaseous stream routed to a fuel gas system (§63.1562(f)(5)). The refinery is presently subject to this subpart and compliance is required in the facility's Part 70 permit. The proposed projects are not expected to change the applicability of this subpart to any of the existing process units.

Subpart YYYY, Stationary Combustion Turbines. This subpart affects new and reconstructed stationary turbines constructed after January 14, 2003. This project will not involve the addition or modification of any turbines. Therefore, this subpart is not applicable.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart was promulgated on February 26, 2004 and affects existing, new, and reconstructed spark ignition 4-stroke rich-burn (4SRB) RICE, new or reconstructed spark ignition 2-stroke lean-burn (2SLB) RICE, new or reconstructed 4-stroke lean-burn (4SLB) RICE, and new or reconstructed compression ignition (CI) RICE, with a site-rating greater than 500 brake horsepower, that are located at a major source of HAP emissions. There are no new or reconstructed RICE as part of this project.

Subpart DDDDD, Industrial/Commercial/Institutional Boilers and Process Heaters. This subpart was published in the Federal Register on September 13, 2004, and affects new, reconstructed, and existing boilers and process heaters fired with solid, liquid, and gaseous fuels. All of the new process heaters and boilers included in this project are large units, defined as watertube boilers and process heaters with heat input capacities greater than 10 million British thermal units per hour (MMBtu/hr). All the new boilers and process heaters will be fired with natural gas, refinery fuel gas, and/or PSA offgas.

In March, 2007, the EPA filed a motion to vacate and remand this rule back to the agency. The rule was vacated by court order, subject to appeal, on June 8, 2007. No appeals were made and the rule was vacated on July 30, 2007. EPA is planning on issuing guidance (or a rule) on what actions applicants and permitting authorities should take regarding MACT determinations under either Section112(g) or Section 112(j) for sources that were affected sources under Subpart DDDDD and other vacated MACTs. It is expected that the guidance (or rule) will establish a new timeline for submission of section 112(j) applications for vacated MACT standards. At this time, AQD has determined that a 112(j) determination is not needed for sources potentially subject to a vacated MACT, including Subpart DDDDD. This permit may be reopened to address Section 112(j) if necessary.

CAM, 40 CFR Part 64 [Not Applicable]
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 of a criteria pollutant, 10 TPY of an individual HAP, or 25 TPY of total HAPs.

None of the process heaters and boilers for this project uses a control device to achieve compliance with an emissions limitation and none of the individual heaters or boilers have the potential to emit more than 100 TPY of a criteria pollutant. Therefore, CAM is not applicable to this project.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility will not process or store more than the threshold quantity of any regulated substance (Section 112r of the Clean Air Act 1990 Amendments). More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and F Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I

& II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

Conditions are included in the permit to address the recordkeeping requirements specified at §82.13 of this regulation. Recordkeeping requirements specific to manufacturing facilities include those for importers of Class I substances, or for persons who destroy Class I controlled substances.

SECTION VIII. COMPLIANCE

Tier Classification and Public Review

This application has been determined to be Tier II based on the request for 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 has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the real property.

The applicant published the "DEQ Notice of Filing a Tier II Application" in the *Ponca City News*, a daily newspaper in Kay County, on February 2, 2007. The notice stated that the application was available for public review at the Ponca City Library, located at 515 E. Grand Ave., Ponca City, Oklahoma, or at the AQD main office. A copy of the draft permit has also been made available to the public and the "DEQ Notice of Tier II Draft Permit" published. The applicant requested concurrent public and EPA review for this permit modification. A copy of the draft permit was sent to EPA Region VI for a 45-day review period. Neither the public nor EPA has offered any comments on the draft or proposed permit.

The facility is located within 50 miles of the border of Kansas and Oklahoma. A letter has been sent to the state of Kansas advising them of the availability of the draft permit.

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 permit fee of $1,500 for modification of a Part 70 source construction permit has been paid.

SECTION IX. 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 Company **Permit No. 2007-042-C (PSD)**
Ponca City Refinery
Refinery Upgrade Projects

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on January 26, 2007 with supplemental information submitted on February 15, 2008, March 3, 2008, and October 10, 2008. The Evaluation Memorandum dated February 2, 2009, 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 emission, emission limitations, and standards** [OAC 252:100-8-6(a)]

a. Process Heaters and Leased Boilers

The following emission limits apply to the new process heaters and leased boilers.

Emission Unit	**Pollutant**	**Emissions**	
		lb/hr (1)	**TPY** (1)
NH-1 Reformate Splitter Reboiler 131 MMBtu/hr (2)	NO_X	3.94	17.3
	SO_2	1.58	6.9
	CO	5.25	23.0
	VOC	0.71	3.1
	PM_{10}	0.98	4.3
NH-3 No. 4 CTU Vacuum Heater 45 MMBtu/hr (2)	NO_X	1.35	5.9
	SO_2	0.54	2.4
	CO	1.80	7.9
	VOC	0.24	1.1
	PM_{10}	0.34	1.5
NH-4 No. 4 CTU Crude Heater 125 MMBtu/hr (2)	NO_X	3.75	16.4
	SO_2	1.50	6.6
	CO	5.00	21.9
	VOC	0.68	3.0
	PM_{10}	0.94	4.1
NH-5	NO_X	2.94	12.9

Emission Unit	Pollutant	Emissions	
		lb/hr [1]	TPY [1]
No. 1 CTU Tar Stripper Heater 98 MMBtu/hr [2]	SO_2	1.18	5.2
	CO	3.92	17.2
	VOC	0.53	2.3
	PM_{10}	0.74	3.2
TB-1 Leased Boiler 95 MMBtu/hr [2]	NO_X	3.42	15.0
	SO_2	0.05	0.2
	CO	3.80	16.6
	VOC	0.51	2.2
	PM_{10}	0.71	3.1
TB-2 Leased Boiler 95 MMBtu/hr [2]	NO_X	3.42	15.0
	SO_2	0.05	0.2
	CO	3.80	16.6
	VOC	0.51	2.2
	PM_{10}	0.71	3.1
TB-3 Leased Boiler 95 MMBtu/hr [2]	NO_X	3.42	15.0
	SO_2	0.05	0.2
	CO	3.80	16.6
	VOC	0.51	2.2
	PM_{10}	0.71	3.1

1. 365-day rolling average including startup, shutdown, and malfunction emissions.
2. For information purposes only, not a limit.

i. TB-1, TB-2, and TB-3 are subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements and standards, including but not limited to:[40 CFR 60.100 - 108]

   a. §60.104 Standards for sulfur oxides. TB-1, TB-2, and TB-3 shall combust only pipeline grade natural gas.
   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.

ii. NH-1, NH-3, NH-4, and NH-5 are subject to 40 CFR Part 60, Subpart Ja and shall comply with all applicable requirements and standards, including, but not limited to:

   a. §60.102a Emission limitations.
   b. §60.103a Work practice standards.
   c. §60.104a Performance tests.
   d. §60.107a Monitoring of emissions and operations for fuel gas combustion devices. Continuous monitoring systems shall be operated and maintained to record the H_2S content of the fuel gas burned in NH-1, NH-3, NH-4, and NH-5. Continuous monitoring systems shall be operated and maintained to record NO_X emissions to the

atmosphere from NH-1 and NH-4. Biennial performance tests shall be conducted for NH-3 and NH-5 to demonstrate compliance with the NO_X emission limits.

e. §60.108a Reporting and recordkeeping requirements.

iii. Compliance of NH-1, NH-3, NH-4, and NH-5 with the SO_2 emission limits of Specific Condition 1.A shall be based on a 365-day rolling average fuel gas usage and H_2S content and shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$SO_2\text{, TPY} = \frac{\text{MMSCFD} * \text{ppmvd } H_2S * 64 \text{ lb } SO_2\text{/lb-mole} * 365 \text{ days/year}}{2000 \text{ lb/ton} * 379.4 \text{ Scf/lb-mole}}$$

iv. Boilers TB-1, TB-2, and TB-3 shall combust pipeline grade natural gas only, which demonstrates compliance with the SO_2 emissions limits of Specific Condition 1.A.

v. Heaters NH-1 and NH-4 shall be constructed with Ultra-Low NO_X burners with NO_X emissions limited to no greater than 0.03 lbs/MMBtu (HHV). Compliance will be demonstrated monthly using on-line continuous monitoring systems and shall be based on 365-day rolling averages, including periods of startup, shutdown, and malfunction. Heaters NH-3 and NH-5 shall be constructed with Ultra-Low NO_X burners with NO_X emissions limited to no greater than 0.03 lbs/MMBtu (HHV). Compliance will be demonstrated via initial and biennial performance tests. CO emissions for heaters NH-1, NH-3, NH-4, and NH-5 shall be limited to no greater than 0.04 lb/MMBtu (HHV). Compliance will be demonstrated via an initial performance test and use of good combustion practices. [OAC 252:100-8-6(a)]

vi. Boilers TB-1, TB-2, and TB-3 shall be constructed with Ultra-Low NO_X burners with NO_X emissions limited to no greater than 0.036 lb/MMBtu (HHV) Compliance will be demonstrated via initial performance test. CO emissions for boilers TB-1, TB-2, and TB-3 shall be limited to no greater than 0.04 lb/MMBtu (HHV). Compliance will be demonstrated via use of good combustion practices. [OAC 252:100-8-6(a)]

vii. Compliance of NH-1, NH-3, NH-4, NH-5, TB-1, TB-2, and TB-3 with the NO_X, CO, VOC, and PM_{10} annual emission limits shall be based on a 365-day rolling average fuel gas usage and heater specific (stack test) emission factors or online instrumentation, when available, or the most current version emission factors from AP-42 Table 1.4-1. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$\text{TPY} = \frac{\text{MMSCFD} * \text{Btu/Scf (HHV)} * \text{EF} * 365 \text{ days/year}}{2000 \text{ lb/ton}}$$

where EF = Emission Factor, lb/MMBtu

viii. Within 60 days of achieving maximum firing rate from the heaters/reboilers, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall, for each process heater and leased boiler, conduct performance testing for NO_X and CO and furnish a written report to Air Quality documenting compliance with emission limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR Part 60:

a. Method 1: Sample and Velocity Traverses for Stationary Sources.
b. Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
c. Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
d. Method 4: Determination of Moisture in Stack Gases.
e. Method 7E: Determination of Nitrogen Oxide Emissions From Stationary Sources.
f. Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources.
g. Method 19: F-factor Methodology.

ix. Performance testing for NO_X and CO shall be conducted while a process heater or leased boiler is operating within 10% of its maximum design firing rate, except for those process heaters or leased boilers that cannot be fired within 10% of the maximum design firing rate due to process limitations and/or production limitations. In those cases, the permittee shall conduct an initial performance test at the maximum firing rate possible under the present operating conditions and within the time guidelines given above. The permittee shall include in the written performance test report submitted to Air Quality the reasons for testing the process heater at less than 90% of the maximum design firing rate. The permittee shall then conduct testing of the process heater or leased boiler at least once per calendar quarter using a portable analyzer in accordance with a protocol meeting the requirements of the latest AQD "Portable Analyzer Guidance" document, or an equivalent method approved by Air Quality. The permittee shall submit the results of quarterly tests to AQD. Within 60 days of achieving 90% or more of maximum firing rate, the permittee shall conduct performance testing using the test methods specified in 40 CFR Part 60 and furnish a written report to Air Quality documenting compliance with emission limitations. If the second performance test demonstrates that the process heater or leased boiler is in compliance with all emission limitations, no additional quarterly testing will be required. 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.

x. Upon startup of NH-3, existing No. 4 CTU vacuum heater H-3 shall be removed from service.

xi. Upon startup of NH-4, existing No. 4 CTU crude heater H-4 shall be removed from service.

xii. Upon startup of NH-5, existing No. 1 CTU tar stripper heater H-5 shall be removed from service.

B. Fugitive Components

Equipment counts and emissions for equipment leaks associated with the projects included in this permit are estimates only and are included solely for the purposes of documenting regulatory applicability. 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 Specific Conditions listed in this section.

Type of Component	**Number of Components**
No. 1 Sustaining Project and No. 4 CTU Revamp Project	
GGG Components Added:	
Gas valves	190
Light liquid valves	250
Heavy liquid valves	250
Flanges	2484
Light liquid pumps	0
Heavy liquid pumps	5
Gas compressors	0
Gas relief valves to atmosphere	0
Gas relief valves to flare	2
Sample Stations	0
QQQ Components Added:	
Process drains (controlled)	10
Junction (or water draw) boxes (controlled)	0
Benzene Reduction Project	
GGG Components Added:	
Gas valves	360
Light liquid valves	360
Heavy liquid valves	0
Flanges	2592
Light liquid pumps	0
Heavy liquid pumps	8
Gas compressors	1
Gas relief valves to atmosphere	0
Gas relief valves to flare	23
Sample Stations	11
QQQ Components Added:	
Process drains (controlled)	35
Junction (or water draw) boxes (controlled)	10

Type of Component	**Number of Components**
Bender Conversion Project	
GGG Components Added:	
Gas valves	20
Light liquid valves	40
Heavy liquid valves	500
Flanges	2016
Light liquid pumps	4
Heavy liquid pumps	10
Gas compressors	0
Gas relief valves to atmosphere	0
Gas relief valves to flare	20
Sample Stations	5
QQQ Components Added:	
Process drains (controlled)	40
Junction (or water draw) boxes (controlled)	10

i. 40 CFR Part 60, Subpart GGGa applies to the following affected equipment: each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment. The permittee shall comply with the applicable sections for each affected component: [40 CFR 60.590a – 593a]

a. §60.592a Standards
b. §60.593a Exceptions

ii. 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 connection in HAP service. The permittee shall comply with the applicable sections for each affected component. [40 CFR 63.640 – 654]

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

iii. NESHAP 40 CFR Part 61, Subpart FF applies to the process sewer system in benzene service. The permittee shall comply with all applicable standards, including but not limited to: [40 CFR 61.340 – 357]

a. §61.346 Standards: Individual drain systems
b. §61.349 Standards: Closed vent systems and control devices
c. §61.350 Standards: Delay of repair
d. §61.353 Alternative means of emission limitation

e. §61.354 Monitoring of operations
f. §61.355 Test methods, procedures, and compliance provisions
g. §61.356 Record keeping requirements
h. §61.357 Reporting requirements

iv. NSPS 40 CFR Part 60, Subpart QQQ applies to individual drain systems and aggregate facilities for process water collection and treatment. The permittee shall comply with all applicable standards, including but not limited to: [40 CFR 60.690 – 698]

a. §60.692-2 Standards: Individual drain systems
b. §60.692-3 Standards: Oil-water separators
c. §60.692-5 Standards: Closed vent systems and control devices
d. §60.692-6 Standards: Delay of repair
e. §60.692-7 Standards: Delay of Compliance
f. §60.693-1 Alternative standards for individual drain systems
g. §60.694 Permission to use alternative means of emission limitations
h. §60.696 Test methods, procedures, and compliance provisions
i. §60.697 Recordkeeping requirements
j. §60.698 Reporting requirements

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

3. The permittee shall file an application to update the facilities Part 70 permit within 180 days of start-up to incorporate the requirements of this permit. [OAC 252:100-8-6(a)]

4. The permittee shall keep records of compliance as specified in Specific Condition No. 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 (5) 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

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(December 22, 2008)

SECTION I. DUTY TO COMPLY

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

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

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

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

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

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

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

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

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

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

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

B. Records of required monitoring shall include:

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

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

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

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions.

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

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

F. Any document submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." However, an exceedance report that must be submitted within ten days of the exceedance under Section II (Reporting Of Deviations From Permit Terms) or Section XIV (Emergencies) may be submitted without a certification, if an appropriate certification is provided within ten days thereafter, together with any corrected or supplemental information required concerning the exceedance.

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1) and OAC 252:100-9-3.1(c)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

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

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.
[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

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

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

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.
[OAC 252:100-8-6(c)(5)(A), and (D)]

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

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

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

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

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

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

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

SECTION VI. PERMIT SHIELD

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

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

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

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

SECTION VIII. TERM OF PERMIT

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

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

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

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

SECTION IX. SEVERABILITY

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

SECTION X. PROPERTY RIGHTS

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

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

SECTION XI. DUTY TO PROVIDE INFORMATION

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

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

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

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

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

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

SECTION XII. REOPENING, MODIFICATION & REVOCATION

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

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

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances:

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

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

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

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

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

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

SECTION XIII. INSPECTION & ENTRY

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

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

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

SECTION XIV. EMERGENCIES

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

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

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance.

[OAC 252:100-8-6(a)(3)(C)(iii)(II)]

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

[OAC 252:100-8-2]

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

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

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

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

SECTION XV. RISK MANAGEMENT PLAN

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

SECTION XVI. INSIGNIFICANT ACTIVITIES

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

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

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

SECTION XVIII. OPERATIONAL FLEXIBILITY

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

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

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

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

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

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

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

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter.
[OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for:
   (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
   (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
   (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
   (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.
[OAC 252:100-25]
(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

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

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

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

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances:

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

[40 CFR 82, Subpart A]

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:

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;

(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

[40 CFR 82, Subpart F]

SECTION XXI. TITLE V APPROVAL LANGUAGE

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

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).
(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

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

SECTION XXII. CREDIBLE EVIDENCE

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

[OAC 252:100-43-6]

ConocoPhillips
Attn: Dave Gamble
Consultant - Environmental
P.O. Box 1267, 1228EB
Ponca City, OK 74602-1267

Re: Permit Number **2007-042-C (PSD)**
Refinery Upgrade Projects

Dear Mr. Gamble:

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

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

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

Sincerely,

John Howell, P.E.
Existing Source Permit Section
AIR QUALITY DIVISION

Enclosure

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. 2007-042-C (PSD)

ConocoPhillips Company,

having complied with the requirements of the law, is hereby granted permission to construct the specified equipment for the Refinery Upgrade Projects at the Ponca City Refinery located in Ponca City, Kay County, Oklahoma, subject to Standard Conditions dated January 24, 2008, and Specific Conditions, both attached.

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

Director, Air Quality Division

2-9-09

Date