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OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **June 8, 2010**

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THROUGH:	Kendal Stegmann, Senior Environmental Manager, Compliance and Enforcement
THROUGH:	David Schutz, P.E., New Source Section
THROUGH:	Peer Review
FROM:	John Howell, P.E., Existing Source Permit Section
SUBJECT:	Evaluation of Permit Application No. 98-104-C (M-6) ConocoPhillips Company, Ponca City Refinery Refinery 2010-2011 Turnaround 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) in Ponca City, Oklahoma. The Refinery's primary Standard Industrial Classification (SIC) Code is 2911 (Petroleum Refining). The Refinery is a Title V major source whose operating permit was issued by the Oklahoma Department of Environmental Quality (DEQ) on December 13, 2007. 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 codified in 40 CFR Part 63, Subpart CC. The applicant submitted the original permit application on July 7, 2009 to implement several upgrades. Some of the construction requested in that application would have been subject to full PSD review. However, the Refinery has recently submitted a revision to the application. The construction requested in the revised application is not subject to PSD review.

The applicant is requesting a construction permit for the following activities:

- No. 4 FCC 2010 Turnaround
  - Replace Regenerator Air Grid - this project has been cancelled
  - Replace Reactor Cyclone Diplegs
  - Replace Main Fractionator Air Cooler
  - Main Fractionator Improvements - this project has been cancelled
- No. 5 FCC 2011 Turnaround
  - Replace Reactor Cyclones
  - Replace Catalyst Stripper Internals

  - Replace Riser (including new riser internals)
- HF Alky 2011 Turnaround
  - Depropanizer Tower Top Replacement
  - Depropanizer Shell and Tube Heat Exchanger Bypasses
- No. 1 CTU Diesel Recovery Improvements
- No. 2 CTU Diesel Recovery Improvements - this project has been cancelled

The Refinery is also planning to install the following additional project:
- No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT.

This permit application revision also includes permit application updates requested on March 19, 2010. Specifically, the Refinery requested to include NOx emission limits for the Ponca City Refinery No. 5 Fluidized Catalytic Cracking Unit (FCCU) and to include emission limits and conditions established pursuant to Federal Consent Decree C.A. No. H-01-4430 (Consent Decree) lodged against Conoco, Inc., entered on April 30, 2002 and amended on August 2, 2003 and October 24, 2006, to which the State of Oklahoma is a Plaintiff-Intervener. Per the conditions of the Consent Decree, once these emission limits and conditions have been included in Permit No. 98-104-C (M-6), the permit should not be superseded by the Ponca City Refinery Title V Permit No. (98-104-TV).

The projects listed above that are included in this permit application 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 2010-2011 time period. Specific details of these projects are included in Section 4.

The emission increases associated with the projects being proposed in the application are summarized in Table 1-1. As indicated, emissions increases resulting from the projects included in this permit application were calculated on a pollutant-by-pollutant basis using the actual-to-potential test described in OAC 252:100-8-30(b)(6) for CO, VOC, and PM_{10} and the actual-to-projected-actual test described in OAC 252:100-8-30(b)(3) for NO_X and SO_2. As such, the Refinery will be subject to the monitoring and recordkeeping requirements of OAC 252:100-8-36.2(c)(3) for NO_X and SO_2. Because the projects will not increase the design capacity or potential to emit of any of the modified or associated sources, the monitoring and recordkeeping required by OAC 252:100-8-36.2(c)(3) must be maintained for 5 years following resumption of regular operations after completion of the proposed projects.

TABLE 1-1. PROJECT EMISSION INCREASES FOR PSD REGULATED POLLUTANTS

Pollutant	Significant Emissions Increase Test	Emission Rate (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review?
CO	Actual-to-Potential	33.3	100	No
PM_{10}	Actual-to-Potential	61.4	15	Yes
$PM_{2.5}$	Actual-to-Potential	61.4	10	Yes
NO_X	Actual-to-Projected-Actual	38.0	40	No
SO_2	Actual-to-Projected-Actual	39.3	40	No
VOC	Actual-to-Potential	22.5	40	No

The Refinery is unaware of any measurable lead (Pb) emissions from the Ponca City facility. Because the Pb emissions were determined to not exist, additional consideration of Pb was not carried forward through the remainder of this application.

Because the total project emissions increases for CO, NO_X, SO_2, and VOC were less than the PSD Significant Emission Rates, further PSD review was not required for those pollutants. Only PM_{10} and $PM_{2.5}$ were included in further PSD review (e.g. netting analysis).

As summarized in Table 1-2, the attributable PM_{10} emissions associated with the planned projects in this permit application did not exceed the PSD significance level. Therefore, the proposed changes are not subject to PSD permitting requirements per Oklahoma Administrative Code (OAC) 252:100-8-30.

TABLE 1-2. NET CONTEMPORANEOUS EMISSION CHANGES FOR PSD REGULATED POLLUTANTS

Pollutant	Emission Rate (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review?
PM_{10}	-75.8	15.0	No
$PM_{2.5}$	-75.8	10.0	No

$PM_{2.5}$ Compliance

The Federal Environmental Protection Agency (EPA) finalized the PSD $PM_{2.5}$ regulations in May 2008. In the Federal Register notice announcing this regulation, 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 have 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[1].

On March 29, 2010, Oklahoma DEQ notified the Refinery that the $PM_{2.5}$ surrogate policy was no longer sufficient and that estimation of $PM_{2.5}$ emissions for this permit application would be necessary. However, the Oklahoma DEQ agreed that the permit was not significant for PM_{10} and that if PM_{10} and $PM_{2.5}$ emissions were assumed to be the same, which would be an over-estimation of the $PM_{2.5}$ emissions since $PM_{2.5}$ is a subset of PM_{10}, then the permit would also not be significant for $PM_{2.5}$ (i.e. because the net PM_{10} emissions were -75.8 TPY, which is less than the PM_{10} significance level of 15 TPY, it would also be less than the $PM_{2.5}$ significance level of 10 TPY). As such, the projects included in this permit application do not trigger PSD for $PM_{2.5}$.

Flare PSD Applicability

The modification of existing equipment and its impact on whether the Refinery flares are subject to PSD review was evaluated. None of the projects included in this permit application will include new or replacement of existing pressure relief valves (PRVs). Also, the projects included in this permit application are not projected to have an increase in malfunction events resulting in releases at any of the Refinery flares. As a result of the Consent Decree, the Refinery has implemented a vigorous flare

[1] 73 Fed. Reg. 28321, 28340-28341 (May 16, 2008)

minimization program, resulting in a significant decrease in malfunction events. As such, because there are no projected emission increases from any of the Refinery flares, they are not subject to PSD review.

SECTION II. PROCESS AND PROJECT DESCRIPTION

The ConocoPhillips Ponca City Refinery (the 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
- 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 and their respective benefits.

No. 4 Fluid Catalytic Cracking Unit

A fluidized catalytic cracking unit (FCCU) converts gas oil (which boils at 650^{O}F to 1050^{O}F) to gasoline, diesel fuels and lighter hydrocarbon products including Refinery fuel gas (RFG) and propane/propylene-butane/butylene (PB) liquid. The gas oil is contacted with a fine powdery catalyst in the riser of the converter vessel at temperatures in excess of 900^{O}F to “crack” the heavy, high boiling-range gas oil material into lighter gasoline and diesel fuel products.

Catalyst is separated from the cracked petroleum products in the reactor/disengager portion of the converter vessel. The catalyst is stripped with steam to remove hydrocarbon clinging to the surface of the particles and then transferred to the regenerator portion of the converter vessel where coke material, which is produced during the cracking reactions, is burned with air, provided by the regenerator air blower, in a continuous process that produces a stream of flue gas. The regenerated catalyst is then contacted with more gas oil and sent back to the riser/reactor. Catalyst carried with the flue gas from the regenerator is separated from the gas by internal cyclones (99.998% efficiency). A small amount of catalyst is eventually broken down in the high temperature regenerator environment to a size small enough to pass through the cyclone separators.

The regenerator flue gas is cooled in a waste heat boiler that recovers heat to produce steam that is used by other Refinery applications. The No. 4 FCCU waste heat boiler is a simple shell-and-tube heat exchanger and is not gas fired. The cooled flue gas then passes through a wet gas scrubber (WGS) to reduce sulfur dioxide (SO_2) and particulate matter (PM) emissions before being discharged to the atmosphere from the WGS stack.

Located immediately downstream of the FCCU converter is the product fractionation process unit which consists of three sections: Heavy Product Fractionation, Gas Recovery Plant, and Light Product Fractionation.
The purpose of the main fractionation (main frac.) column of the Heavy Product Fractionation section is to quench the FCCU disengager overhead vapor and separate the unreacted heavier liquid fractions from the total stream. This results in the recovery of light cycle oil (LCO), which is sent to the No. 9 Hydrotreater (HDT) for sulfur removal/reduction, naphtha, which is sent to gasoline blending, and bottoms slurry (decant oil), which is fed to the Coker unit or sold. The remaining light liquids and gases are further separated in the Vapor Recovery Unit (VRU) which is made up of the Gas Recovery Plant and Light Product Fractionation section.

The Gas Recovery Plant takes the gas from the Heavy Product Fractionation section, chills it with SUVA® refrigeration and separates the non-condensable and condensable hydrocarbons. This results in the recovery of valuable light liquid products that go to the Light Product Fractionation section for further separation. The gases are amine treated and sent to the Refinery fuel gas system.

In the Light Product Fractionation section, the FCCU gasoline stream is stabilized by the removal of the condensable PB hydrocarbons. The gasoline is sent to the No. 8 HDT for sulfur removal/reduction and the PB liquid is sent to the No. 5 FCCU VRU for further processing.

The No. 4 FCCU 2010 turnaround will include a number of work items necessary to address mechanical integrity issues and projects to modify product yields. The following is a summary list of the turnaround work and projects.

Main Frac. Column Overhead Air Cooler Replacement

The No. 4 FCCU main frac. column overhead air cooler, X-6130, was installed in 1978 and is made up of 3 banks; each bank having 4 rows of tubes that are nearing the end of their useful thickness. The tubes will be replaced with same-size equipment (i.e. same tube internal diameter) and an additional row of tubes will be added to each bank. The additional row of tubes will decrease pressure drop across the air cooler and, ultimately, reduce pressure in the No. 4 FCCU regenerator, which will increase air flow rate, and so increase coke burn rate in the regenerator. The increase in coke burn can be used to either increase unit feed rate at constant conversion, or increase conversion at constant unit feed rate. As described in the No. 1 CTU diesel recovery improvement project below, the Refinery expects diesel oil to increase in value over gasoline in the coming years. As such, production of gas oil, the No. 4 FCCU feedstock, from the refinery crude topping units will decrease in order to increase diesel oil yield. Therefore, because FCCU feed stock volume is expected to decrease in the future, the pressure drop reduction resulting from the additional row of air cooler tubes will be used to change the yield pattern of the total No. 4 FCCU product streams; specifically, to increase yields of PB, gasoline and LCO and reduce decant yield.

Reactor Cyclone Dipleg Replacement

On a number of occasions, one or more of the No. 4 FCCU reactor secondary cyclone diplegs have become plugged during unit start-up or shutdown, which, in turn, has resulted in catalyst losses and additional unplanned unit shut downs. This project will install larger diameter diplegs on the reactor secondary cyclones to help prevent this problem. This project is intended to reduce unit start-up emissions and will not increase the capacity of the No. 4 FCCU.

TABLE II-1. NO. 4 FCCU 2010 TURNAROUND PROJECTS – AFFECTED EMISSIONS UNITS

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 4 FCCU	FCCU Stack	Increase in actual emissions	There are no proposed changes to permit limits or maximum emission rates as result of the project.

No. 5 Fluid Catalytic Cracking Unit

The No. 5 FCCU converter is similar to that of the No. 4 FCCU except that it includes a gas-fired CO boiler, B-5004, instead of a shell-and-tube heat exchanger. B-5004 is a tubed boiler that produces high pressure steam by recovery of heat from the regenerator flue gas and is supplementally gas fired with refinery fuel gas (RFG). B-5004 also includes an enhanced selective non-catalyst reduction (E-SNCR) system to reduce nitrogen oxide (NO_X) emissions. As with the No. 4 FCCU, the cooled flue gas then passes through a wet gas scrubber (WGS) to reduce sulfur dioxide (SO_2) and particulate matter (PM) before being discharged to the atmosphere from the WGS stack.

Like the No. 4 FCCU, the No. 5 FCCU includes a main fractionator tower, which is used to quench the FCCU disengager overhead vapor and separate the unreacted heavier liquid fractions from the total stream. This results in the recovery of LCO, which is sent to the No. 9 HDT for sulfur removal/reduction, naphtha, which is sent to gasoline blending, and bottoms slurry, which is sold. The remaining light liquids and gases are further separated in the Vapor Recovery Unit (VRU), which is made up of the Gas Recovery Plant, the No. 1 Cryogenic Unit and Light Product Fractionation section.

The Gas Recovery Plant takes the gases from the Heavy Product Fractionation section and wet gases from the Coker unit and separates the non-condensable and condensable hydrocarbons. This results in the recovery of valuable light liquid products that go to the Light Product Fractionation section for further separation. The gases are amine treated and sent to the No. 1 Cryogenic Unit, which recovers additional light liquid products and sends the remaining gases to the Refinery fuel gas system.

In the Light Product Fractionation section, the FCCU gasoline stream is stabilized by the removal of the condensable propane/propylene-butane/butylene (PB) hydrocarbons. The gasoline is sent to the No. 8 HDT for sulfur removal/reduction and the PB liquid is combined with No. 4 FCCU PB liquid and sent to the depropanizer column for separation into propane-propylene liquid (PP) and butane-butylene liquid (BB). The PP liquid is amine treated and sent off for further processing in the Catalytic Polymerization Unit (Cat Poly) and/or the HF Alkylation Unit (Alky) and/or to sales. The BB liquid is sent off for further processing in the Alky.

The No. 5 FCCU 2011 turnaround will include a number of work items necessary to address mechanical integrity issues and projects to modify product yields. The following is a summary list of the turnaround work and projects.

Reactor Cyclone Replacement

This project will replace the 23-year old No. 5 FCCU reactor cyclones because inspection findings from the last unit turnaround indicated that the hanger and barrels have been experiencing deterioration and general erosion and that repairs which require welding would be impractical due to embrittlement.

In addition to equipment replacement, the configuration of the reactor cyclones will be changed from 4 primary cyclones and 3 secondary cyclones to 1 primary cyclone and 4 secondary cyclones. This modification will not change particulate matter (PM) removal.

The current reactor cyclones are traditional two stage cyclones, uncoupled. The replacement equipment will be Close Coupled Cyclones (CCC), which is the ConocoPhillips best practice riser termination device. The CCC arrangement will reduce over-cracking and dry-gas make and increase liquid yields. The CCC arrangement will require a slightly larger reactor vessel (height will increase by 8 feet and diameter will increase by 2 feet) to accommodate the CCC pairs.

This project will not increase the capacity of the No. 5 FCCU, i.e. debottleneck the unit, but will, instead, increase yields of the unit product streams, specifically LPG (propane-propylene and butane-butylene) and gasoline.

The dry-gas reduction resulting from the CCC arrangement is an integral part of the Ponca City Refinery energy reduction plan. As the refinery reduces fuel usage, fuel gas reduction projects are required to maintain fuel gas balance and realize the full benefit of the energy reduction projects.

During the last unit turnaround, coke build up on the reactor walls was approximately 4-inches thick and resulted in the reactor repair becoming the turnaround critical path repair job. In the root cause analysis, the coke was attributed to multiple startups, lack of dome steam combined and heavier gas oil feed stock. The new reactor cyclone design will include installation of dome steam to minimize coke buildup.

Catalyst Stripper Internals Replacement

This project will replace the internals of the No. 5 FCCU catalyst stripper (disk-and-donut trays also referred to as shed trays), with packing to improve hydrocarbon removal and regenerator catalyst bed temperatures. The improved hydrocarbon removal will, in turn, result in a marginal increase of FCCU product yields. This project will not increase the capacity of the No. 5 FCCU.

Riser Replacement

During the last unit turnaround, cracks along the length of the No. 5 FCCU converter riser were repaired, however the required work time was excessive due to the small diameter working space and difficulty chipping refractory in the limited space. This repair approach is less than ideal based on available repair methods. Therefore, a replacement riser will be fabricated prior to the 2011 turnaround in a shop in order to achieve first-class refractory repair, which will reduce repair time and improve reliability during operation. The new equipment will have the same diameter as the existing riser, but will be longer due to the increased height of the reactor necessary to accommodate the Close Coupled Cyclones described above. Lastly, new internals will be included in the replacement riser to reduce back mixing and increase conversion. In particular, the new internals will result in increased BB and gasoline yields and reduced LCO and decant yields. This project will not increase the capacity of the No. 5 FCCU.

TABLE II-2. NO. 5 FCCU 2011 TURNAROUND PROJECTS – AFFECTED EMISSIONS UNITS

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 5 FCCU	FCCU Stack	Increase in actual emissions	There are no proposed changes to permit limits or maximum emission rates as result of the project.

No. 1 Crude Topping Unit

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 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, pumparound, and recycle streams to the raw crude oil, to the crude oil desalters. The desalters use temperature, pressure, injected water, emulsion breaker chemicals, electric field, 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 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 W-1 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.

Diesel Recovery Improvements

The Refinery expects diesel oil to increase in value over gasoline in the coming years. To that end, this project will make the piping modifications necessary to increase the recovery of diesel oil-range material in No. 1 CTU Crude Tower W-1 and, conversely, reduce recovery of naphtha, kerosene, and atmospheric gas oil-range material. This project will not increase the capacity of the No. 1 CTU, i.e. debottleneck the unit, but will, instead, change the yield pattern of the total unit product streams.

HF Alkylation Unit

The HF Alkylation Unit (Alky) uses hydrofluoric (HF) acid as a catalyst to promote the reaction of olefin with isobutane to form high-octane gasoline blending components. The olefin feed stream to the unit is produced in the fluid catalytic cracking and delayed coking processes. As mentioned in the No. 5 FCCU process description, the olefin feed is split into a propane-propylene stream (PP) and a butane-butylene stream (BB). The BB stream is treated for H_2S removal in the Alky Unit BB Merox Treater prior to feeding the SHP (Selective Hydrogenation Process) unit to remove butadiene and isomerize 1-butene. On the way to the Alky, the PP stream can be processed through the Catalytic Polymerization Unit. Isobutane makeup feed is either produced in the Butamer Unit or purchased from outside the Refinery.

The Alky yields a high-octane gasoline component (alkylate), butane, and propane. There is also a small light ends stream that goes to the Refinery fuel gas system.

The Alky is made up of six main sections: the Deethanizer section, the Merox Treating section, the Reactor Feed and HF Circulation section, the Fractionation section, the Propane and Butane Treating section and the Neutralization section.

The Deethanizer section removes methane, ethane, and most of the H_2S from the PP and cavern charge to the Alkylation Unit. The Deethanizer system consists of a feed surge drum, pumps, a feed/bottoms exchanger, the deethanizer tower with overhead condenser, a reflux drum, a steam heated reboiler, and the bottoms cooler.

The Merox process of the Universal Oil Products Company (UOP) is a chemical treatment for petroleum distillates that removes mercaptans by conversion to byproduct disulfides. First, a mild caustic reacts with H_2S in prewash drums before subsequent contact with a stronger caustic solution in the extractor tower used to extract mercaptan compounds from the PP and BB streams. The mercaptans in the caustic streams are combined and converted to disulfides in the common Merox unit consisting of one oxidizer drum, disulfide separator, alkylate-caustic separator, and associated pumps and heat exchangers.

In the Reactor Feed and HF Circulation section of the unit, the makeup isobutane and the olefin feed are dried and combined with the recycle isobutane before entering the reactor legs. The reactor products are separated, and the HF is recycled and cooled, and a slip stream of HF is regenerated. This section consists of a cavern wash drum, feed sphere, feed driers, reactor/settler vessel, acid coolers, acid rerun column, acid soluble oil (ASO) neutralizer, and associated pumps and exchangers.

In the Fractionation section, the depropanizer separates the hydrocarbon feed from the acid settler into HF acid and propane as the overhead product, isobutane as a side draw product for recycle reactor feed and alkylate as a bottoms product.

The depropanizer has a pumped reboiler circuit which includes gas-fired reboiler H-60. This furnace includes an air preheat system to increase the furnace efficiency and thus reduce fuel consumed. This is accomplished by preheating the combustion air through a rotating heat exchanger which alternately contacts the cool air and hot flue gas. A forced draft fan pushes air through the preheater to the furnace, and an induced draft fan pulls flue gas from the preheater and pushes it to the flue stack.

The purpose of the debutanizer is to separate normal butane from the alkylate, thus reducing the alkylate vapor pressure. The debutanizer reboiler is a thermosiphon heater utilizing 175 psig steam on the tube side.

The Propane and Butane Treating section uses defluorinators to lower the fluoride content of the product. The propane treating system consists of defluorinators, a KOH treater, and three heat exchangers. The butane treating system consists of defluorinators, a KOH treater, and four heat exchangers.

In the Neutralization section, traces of HF are removed from gases relieved from process vessels and equipment. These gases pass through the Acid Relief Neutralizer before entering the main flare header. The neutralizer contains a solution of 45 percent potassium hydroxide (KOH) when freshly added to the system.

The KOH neutralizes the HF contained in the relief gases from the acid section of the Alky Unit. Without neutralization, HF would cause excessive corrosion in the carbon steel flare system downstream of the acid neutralizer.

The Alky 2011 turnaround will include minor upgrade and safety-related projects. The following is a summary list of the turnaround work items and projects.

Depropanizer Shell and Tube Heat Exchanger Bypasses

HF acid causes significant fouling in the tube bundles of Alky depropanizer shell and tube heat exchangers X-966 and X-967. In particular, the HF acid reacts with the carbon steel tube bundles, which forms iron fluorides (FeF_2) that accumulate on the tube walls. Iron fluorides have about 3 times the volume of carbon steel. Also, the iron fluorides can flake off of the tube walls and cause plugging problems.

Fouling due to iron fluoride formation causes an increase in pressure drop across the heat exchangers, which, in turn, reduces unit feed capacity. As a result, the tube bundles must be replaced approximately every 2½ years, while unit turnarounds are scheduled for every 5 years. Replacement of any of the heat exchanger tube bundles outside of a unit turnaround can only be done if the entire unit is shut down. Typical duration of an Alky shutdown to replace tube bundles is approximately 10 to 14 days.

Alky shutdowns and startups increase the safety risks associated with HF acid, including corrosion and personnel exposure. Eliminating the extra shutdown to replace tube bundles in X-966 and X-967 will reduce these safety risks.

This project will install bypass lines around the tube sides of shell and tube heat exchangers X-966 and X-967 and the shell side of shell and tube heat exchanger X-966. The purpose of these bypasses is to provide an alternate route for the process material while maintenance work is being performed on the heat exchangers.

Depropanizer Tower Top Replacement

Prior to the last Alky turnaround, inspection identified thinning areas in the Alky depropanizer tower shell. Based on identified corrosion rates, the tower was rerated and projected to reach minimum required thickness in the identified thinning areas between 2011 and 2016.

This project will replace the top 75' of the depropanizer tower shell, which is approximately 175' tall. In addition to replacing the fractionation trays in the top section, the fractionation trays in the remainder of the depropanizer tower will also be replaced. The new trays will improve the fractionation efficiency of the depropanizer, enabling the tower to operate with better liquid separation and less corrosion. In particular, the new trays will increase the purity of the isobutane side draw, which will, in turn, improve alkylate octane. As a result of the increased alkylate octane, the refinery will be able to reduce the octane/severity of the catalytic reformers. This project will not increase the capacity of the Alky, i.e. debottleneck the unit.

TABLE II-3. HF ALKYLATION UNIT TURNAROUND PROJECTS – AFFECTED EMISSIONS UNITS

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
HF Alky	Fugitive Emissions	New piping fugitive components being added as part of the project	Potential to emit rates from fugitive components in the HF Alkylation Unit will increase as a result of the projects.

No. 6 Hydrotreater

The No. 6 Hydrotreater (HDT) Unit uses hydrogen in the presence of a Cobalt, Nickel, and Molybdenum catalyst to remove sulfur from distillate streams. During normal operation the feed streams to the unit are heating oil distillate and kerosene from the No. 1 CTU, No. 2 CTU, and No. 4 CTU virgin distillate from storage can also be fed to the unit.

The No. 6 HDT Unit yields a desulfurized distillate product, unstabilized light distillate, and light ends that go to the No. 2 Cryo unit and the fuel gas system.

The No. 6 HDT Unit can be divided into five sections: Hydrogen Compressor, Reactor Circuit, Product Separation, Amine Treating, and Permeator. The following is a brief description of the five sections of the No. 6 HDT Unit.

The Hydrogen Compressor boosts the pressure of the unit make-up and recycle hydrogen streams to the required reaction pressure. The motor-driven reciprocating compressor consists of four stages of compression with interstage cooling, suction filters, knockout drums, and suction and discharge pulsation dampener bottles.

In the Reactor Circuit section of the unit, the distillate/hydrogen feed is heated in exchange with the reactor charge/product exchanger train. The distillate/hydrogen mixture undergoes an exothermic reaction and the reactor effluent is cooled with the feed/effluent exchangers.

The purpose of the Product Separation section of the unit is to separate and remove the hydrogen, H_2S, and light ends from the distillate. The product separation section consists of hot and cold high pressure separators, hot and cold low pressure separators, heat exchangers, associated pumps, and a stripping column.

The purpose of the Amine Treating section is to remove hydrogen sulfide from the hydrogen stream off the cold separator. This is called "sweetening" the "sour" stream. The H_2S will build up in the recycle hydrogen stream unless it is removed. Removing the H_2S improves desulfurization in the reactor and reduces the amount of gas purge required to stabilize feed purity.

The purpose of the Permeator section is to purify the hydrogen purged from the hydrogen recycle stream.

No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT

The No. 6 HDT stripping column overhead unstablized naphtha stream is currently sent to the Saturated Gas Plant, and then to one or both of the Refinery catalytic reforming units (CRUs). The unstabilized naphtha stream includes a small amount of heavy hydrocarbon (high molecular weight) which negatively impacts CRU catalyst run length. In order to remove the heavy hydrocarbon from the unstabilized naphtha stream, the No. 6 HDT stripping column must operate at reduced temperatures, which, in turn, causes corrosion issues. This project will install a short length of pipe, called a jumper line, which will combine the No. 6 HDT unstablized naphtha with the No. 5 HDT distillate stream. The combined stream will then be sent to the No. 9 HDT where the heavy hydrocarbon will then be recovered.

TABLE II-4. NO. 6 HDT UNSTABILIZED NAPHTHA JUMPER TO NO. 9 HDT – AFFECTED EMISSIONS UNITS

Unit	Source Description	Project Impact on Emissions Unit	Project Impact on Permit
No. 6 HDT	Fugitive Emissions	New piping fugitive components being added as part of the project	Potential to emit rates from fugitive components in the No. 6 HDT will increase as a result of the projects.

SECTION III. PROJECT EMISSIONS

This section presents the emission calculation methodology used to determine PSD applicability for the modified and associated units, including process heaters, FCCUs, and equipment leaks.

III.1 Definitions

The following definitions apply to the discussion of project emissions in this permit.

<u>Actual Emissions</u>

Actual emissions are defined in 252:100-8-31 as:

The actual rate of emissions of a regulated NSR pollutant from an emissions unit, as determined in accordance with paragraphs (A) through (C) of this definition, except that this definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under OAC 252:100-8-38. Instead, the definitions of "projected actual emissions" and "baseline actual emissions" shall apply for those purposes.

(A) In general, actual emissions as of a particular date shall equal the average rate in TPY at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The Director shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(B) The Director may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(C) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

Baseline Actual Emissions

Baseline actual emissions are defined in 252:100-8-31 as:

For an existing emissions unit (other than an EUSGU), baseline actual emissions means the average rate in TPY, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Director for a permit required either under this Part or under a plan approved by the Administrator, whichever is earlier, except that the 10 year period shall not include any period earlier than November 15, 1990.

(i) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(ii) The average rate shall be adjusted downward to exclude any noncompliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(iii) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a MACT standard that the Administrator proposed or promulgated under 40 CFR 63, the baseline actual emissions need only be adjusted if DEQ has taken credit for such emissions reduction in an attainment demonstration of maintenance plan consistent with requirements of 40 CFR 51.165(a)(3)(ii)(G).

(iv) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each regulated NSR pollutant.

(v) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in TPY, and for adjusting this amount if required by (C)(ii) and (iii) of this definition.

Historical emissions from sources affected by the projects included in this permit application have been calculated from representative historical data. The baseline actual emissions for the projects included in this permit application are based on the most representative operating data for a consecutive 24-month period during the previous 10 years. ConocoPhillips has chosen to use the operating data for the period January 1, 2007 through December 31, 2008 to calculate the baseline actual emissions for all project affected emissions units.

Potential to Emit

Potential to emit is defined in 252:100-8-31 as:

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

Projected Actual Emissions

Projected actual emissions are defined in 252:100-8-31 as:

(A) Projected actual emissions means the maximum annual rate, in TPY, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant, and full utilization of the unit would result in a significant emissions increase, or a significant net emissions increase at the major stationary source.

(B) In determining the projected actual emissions under paragraph (A) of this definition (before beginning actual construction), the owner or operator of the major stationary source:

(i) shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved plan; and

(ii) shall include fugitive emissions to the extent quantifiable and emissions associated with start-ups, shutdowns, and malfunctions; and

(iii) shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,

(iv) in lieu of using the method set out in (B)(i) through (iii) of this definition, may elect to use the emissions unit's potential to emit, in TPY. 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,[2] and the New Source Review Revisions published in the Oklahoma Administrative Code. Emissions netting is a term that refers to the process of considering certain previous and prospective emissions changes at an existing major source to determine the total net emissions increase of a pollutant that will result from a proposed physical change or change in the method of operation. OAC 252:100-8-30(b)(3) through (6) describe test methods for determining if significant emission increases and significant net emission increases have occurred:

> OAC 252:100-8-30(b)(3) Actual-to-projected-actual applicability test for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline actual emissions for each existing emissions unit equals or exceeds the amount that is significant for that pollutant.
>
> OAC 252:100-8-30(b)(4) Actual-to-potential test for projects that only involve construction of a new emissions unit(s). A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit from each new emissions unit following completion of the project and the baseline actual emissions of these units before the project equals or exceeds the amount that is significant for that pollutant.
>
> OAC 252:100-8-30(b)(5) Hybrid test for projects that involve multiple types of emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in OAC 252:100-8-30(b)(3) or (4) as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the amount that is significant for that pollutant. For example, if a project involves both an existing emissions unit and a new emissions unit, the projected increase is determined by summing the values determined using the method specified in

[2] EPA, Office of Air Quality Planning and Standards, *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting*, DRAFT, October 1990.

OAC 252:100-8-30(b)(3) for the existing unit and determined using the method specified in 252:100-8-30(b)(4) for the new emissions unit.

OAC 252:100-8-30(b)(6) Actual-to-potential test for projects that only involve existing emissions units. In lieu of using the actual-to-projected-actual test, owners or operators may choose to use the actual-to-potential test to determine if a significant emissions increase of a regulated NSR pollutant will result from a proposed project. A significant emissions increase of a regulated NSR pollutant will occur if the sum of the difference between the potential emissions and the baseline actual emissions for each existing emissions unit equals or exceeds the amount that is significant for that pollutant. Owners or operators who use the actual to potential test will not be subject to the recordkeeping requirements in OAC 252:100-8-36.2(c).

For CO, VOC, and PM_{10}, the Refinery will utilize the actual-to-potential test for projects that only involve existing emissions units for determining PSD applicability because it involves only modifications to existing equipment. For NO_X and SO_2, the Refinery will utilize the actual-to-projected-actual test for projects that only involve existing emissions units for determining PSD applicability because, again, it involves only modifications to existing equipment.

III.2 Determining Net Emissions

A six-step procedure (summarized below) was used for determining the net emissions change.

Emission Increases from the Project - Determine the emission increases from the project, including any associated emissions increases (i.e. debottlenecking emissions). If increases are above PSD Significant Emission Rates (SERs), proceed; if not, the project is not subject to PSD review.

Contemporaneous Period - Determine the beginning and ending dates of the contemporaneous period as it relates to the project.

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.

Creditable Emissions Changes - Determine which contemporaneous emissions changes are creditable.

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

PSD Review - Sum all contemporaneous and creditable increases and decreases with the emissions changes from the project to determine if a significant net emissions increase will occur.

The following sections detail each of the steps outlined above.

Step 1 – Emission Increases from the Projects

In this step, emissions increases resulting from the projects included in this permit application were calculated on a pollutant-by-pollutant basis using the actual-to-projected-actual test described in OAC

252:100-8-30(b)(3) for NO_X and SO_2 and the actual-to-potential test described in OAC 252:100-8-30(b)(6) for CO, VOC, and PM_{10}. The emissions increases include both project emissions and emissions from sources associated with the project. PSD review for the project is required only for those regulated pollutants that have emissions increases greater than the PSD SERs. Emission decreases are not considered in this step.

FCCU Emissions

The No. 4 FCCU Main Frac. Overhead Air Cooler Replacement project will change the unit product yield distribution by increasing conversion. The project will decrease pressure drop across the overhead air cooler and, ultimately, reduce pressure in the No. 4 FCCU regenerator, which will increase air flow rate, and so increase coke burn rate in the regenerator. The increased coke burn will, in turn, increase conversion. The other No. 4 FCCU 2010 Turnaround project (Reactor Cyclone Dipleg Replacement) will not affect the FCCUs conversion or unit feed rate. Neither of the No. 4 FCCU 2010 Turnaround projects will increase the unit's potential to emit.

The No. 5 FCCU Reactor Cyclone Replacement, Catalyst Stripper Internals Replacement, and Riser Replacement projects will change the unit product yield distribution by reducing hydrocarbon on catalyst, reducing over-cracking, and increasing conversion. These projects will not affect the No. 5 FCCU unit feed rate or the unit's potential to emit.

Fugitive Emissions

The projects included in this permit application will result in an increase in VOC emissions from equipment leaks due to the installation of equipment such as flanges and valves. For the purposes of the PSD applicability emissions analyses, the VOC emission increases associated with the projects included in this permit application were calculated using the number of fugitive components estimated to be added by the projects. For the process units affected by the projects included in this permit application, the emission increases were estimated based on the net change in fugitive components resulting from the 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.[3] Estimated fugitive counts and emissions calculations are presented in Tables A-1, A-2, A-3, A-4, and A-5 of Appendix A.

The No. 4 FCCU Main Frac. Overhead Column Air Cooler Replacement project will install equipment that has the same number of fugitive components as the equipment to be replaced. As such, no fugitive emissions are associated with this project.

All physical modifications for the No. 4 FCCU Reactor Cyclone Dipleg Replacement project are internal to the No. 4 FCCU converter. As such, there are no fugitive components or emissions associated with these projects. Similarly there are no fugitive components or emissions associated with the No. 5 FCCU Reactor Cyclone Replacement, Catalyst Stripper Internals Replacement, and Riser replacement projects.

[3] The emission factors are the "permit quality" emission factors for new sources at the Ponca City Refinery referenced in the March 1, 1991 and March 9, 1991 correspondence to Oklahoma Air Quality Service.

The HF Alky Depropanizer Tower Top Replacement project will install equipment that has the same number of fugitive components as the equipment to be replaced. As such, no fugitive emissions are associated with this project.

Existing Tank Emissions

The projects included in this permit application will result in increased gasoline and diesel oil production. Specifically, the projects will produce an estimated 2,000 BPD of incremental diesel oil, 100 BPD of FCCU gasoline and 600 BPD of alkylate. It was conservatively assumed that the increased throughput would occur in one storage tank for each type of affected tank[4]. The types of affected storage tanks are desulfurized virgin and cracked (FCCU) diesel, FCCU gasoline, alkylate, finished gasoline, and finished diesel.

Emissions were calculated based on the anticipated throughput for the assumed tanks using U.S. EPA's TANKS 4.09d program.

Associated Emission Units

Associated emissions are included for the purpose of verifying PSD applicability or non-applicability and air quality modeling, if necessary. The projects included in this permit application do not include physical modifications to any associated emission units. The associated emission units will continue to operate in compliance with currently applicable rules, regulations, and permit conditions. Therefore, the Refinery requests that this permit not include emission limits or specific conditions for the associated emission units.

Table III-1 summarizes the emission units associated with the projects included in this permit application.

[4] June 17, 2009 phone conversation between Mr. Dave H. Gamble, ConocoPhillips, and Mr. Phillip Fielder, Oklahoma Department of Environmental Quality

TABLE III-1. SUMMARY OF ASSOCIATED EMISSION UNITS

Projects	Associated Emission Unit	ID	Description
No. 4 FCCU 2010 Turnaround	No. 8 HDT	H-8601	Splitter Reboiler
		H-8602	Feed Heater
	No. 1 H2 Plant	H-8801/8802	Reformer
	No. 9 HDT	H-9901	Feed Heater
		H-9902	Stripper Reboiler
	No. 2 H2 Plant	H-9851	Reformer
	HF Alky	H-0060	Depropanizer Reboiler
	Tank	T-0125	Diesel
	Tank	T-0136	Diesel
	Tank	T-0151	Unleaded Gasoline
	Tank	T-0162	FCCU Gasoline
No. 5 FCCU 2011 Turnaround	No. 8 HDT	H-8601	Splitter Reboiler
		H-8602	Feed Heater
	No. 1 H2 Plant	H-8801/8802	Reformer
	No. 9 HDT	H-9901	Feed Heater
		H-9902	Stripper Reboiler
	No. 2 H2 Plant	H-9851	Reformer
	HF Alky	H-0060	Depropanizer Reboiler
	Tank	T-0125	Diesel
	Tank	T-0136	Diesel
	Tank	T-0151	Unleaded Gasoline
	Tank	T-0162	FCCU Gasoline
	Tank	T-0165	Alkylate
No. 1 CTU Diesel Recovery Improvements	No. 6 HDT	H-7501	Reactor Charge Heater
	Tank	T-0125	Diesel
	Tank	T-0135	Diesel
HF Alky 2011 Turnaround	HF Alky	H-0060	Depropanizer Reboiler
	Tank	T-0165	Alkylate
No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT	No. 9 HDT	H-9901	Feed Heater
		H-9902	Stripper Reboiler

NO_X and SO_2 Emissions Increases

As mentioned above, the NO_X and SO_2 emissions increases resulting from the projects included in this permit application were calculated on a pollutant-by-pollutant basis using the actual-to-projected-actual test described in OAC 252:100-8-30(b)(3). As a result, the Refinery will be subject to the monitoring and recordkeeping requirements of OAC 252:100-8-36.2(c) for NO_X and SO_2. Because the projects included in this permit application will not increase the design capacity or potential to emit of any of the modified or associated sources, the monitoring and recordkeeping required by OAC 252:100-8-36.2(c)(3) must be maintained for 5 years following resumption of regular operations after completion of the proposed projects. The following are detailed discussions of the emissions calculations.

No. 4 FCCU SO_2 Emissions

As discussed above, the Refinery has chosen to use the operating data for the time period of January 1, 2007 through December 31, 2008 to calculate the baseline actual emissions for all emissions units affected by the projects included in this permit application.

Per the definition of "baseline actual emissions" included in OAC 252:100-8-31 (see section III.1), "[t]he average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period".

The average No. 4 FCCU SO_2 emission for 2007 was 78.9 ppmvd @ 0% O_2 and the average emission for 2008 was 60.8 ppmvd @ 0% O_2. The No. 4 FCCU became subject to an SO_2 emission limit of 25 ppmvd @ 0% O_2 on a 365-day rolling average basis following installation and startup of a wet gas scrubber for the unit in late 2008[5]. Therefore, the No. 4 FCCU SO_2 emissions for the period of January 1, 2007 through December 6, 2008 were adjusted per the current SO_2 emission limit. The projected actual SO_2 emission value for the No. 4 FCCU was set equal to the Ponca City Refinery Title V permit SO_2 mass emission limit of 55 TPY.

No. 4 FCCU NO_X Emissions

The No. 4 FCCU became subject to a NO_X emission limit of 40 ppmvd @ 0% O_2 on a 365-day rolling average basis beginning October 31, 2005[6]. The average No. 4 FCCU NO_X emission for 2007 was 34.5 ppmvd @ 0% O_2 and the average emission for 2008 was 32.3 ppmvd @ 0% O_2. Because the No. 4 FCCU was in compliance with the emission limit during the baseline period, no adjustment of the actual emissions was required. The projected actual NO_X emission value for the No. 4 FCCU was set equal to 60 TPY.

No. 5 FCCU SO_2 Emissions

The No. 5 FCCU became subject to an SO_2 emission limit of 25 ppmvd @ 0% O_2 on a 365-day rolling average basis following installation and startup of a wet gas scrubber for the unit in late 2006[7]. The average No. 5 FCCU SO_2 emission for 2007 was 15.8 ppmvd @ 0% O_2 and the average emission for 2008 was 15.9 ppmvd @ 0% O_2. Because the No. 5 FCCU was in compliance with the emission limit during the baseline period, no adjustment of the actual emissions was required. The projected actual SO_2 emission value for the No. 5 FCCU was set equal to 80 TPY.

[5] "No. 4 FCCU Wet Gas Scrubber Startup Notification – ConocoPhillips Company – Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated December 18, 2008.

[6] Consent Decree C.A. No. H-01-4430, Paragraph 17D.

[7] "No.5 FCCU Wet Gas Scrubber Startup Notification – Construction permit No. 2003-336-C (M-2) PSD - ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated December 8, 2006.

No. 5 FCCU NO_X Emissions

The No. 5 FCCU accepted a NO_X emission limit of 37.1 ppmvd @ 0% O_2 on a 365-day rolling average basis beginning January 27, 2010[8]. The average No. 5 FCCU NO_X emission for 2007 was 37.3 ppmvd @ 0% O_2 and the average emission for 2008 was 32.8 ppmvd @ 0% O_2. As such, the No. 5 FCCU NO_X emissions for the period of January 1, 2007 through December 31, 2007 were adjusted per the current NO_X emission limit. The projected actual NO_X emission value for the No. 5 FCCU was set equal to 105 TPY.

Fugitive Emissions

Fugitive emissions for the projects included in this permit application are limited to VOCs and so are not included in the NO_X and SO_2 analysis.

Table III-2 summarizes the project NO_X and SO_2 emission increases for the modified sources.

TABLE III-2. SUMMARY OF PROJECT PROJECTED ACTUAL NO_X AND SO_2 EMISSION INCREASES

PROJECT	MODIFIED SOURCES	NO_x (TPY)	SO_2 (TPY)
No. 4 FCC 2010 Turnaround	No. 4 FCCU (Regenerator)	21.5	16.3
	Fugitives	---	---
No. 5 FCC 2011 Turnaround	No. 5 FCCU (Regenerator)	16.5	23.0
	Fugitives	---	---
No. 1 CTU Diesel Recovery Improvements	Fugitives	---	---
HF Alky 2011 Turnaround	Fugitives	---	---
No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT	Fugitives	---	---
	Total	38.0	39.3

Refer to Tables A-8, A-9, A-13, and A-14 in Appendix A for detailed NO_X and SO_2 emissions evaluations.

Associated Emissions Units – Process Heaters

As mentioned above, the Refinery expects diesel oil to increase in value over gasoline in the coming years. As a result, production of gas oil, the No. 4 and No. 5 FCCU feedstock, from the Refinery crude topping units will decrease in order to increase diesel oil yield. Therefore, because FCCU feed stock volume is expected to decrease in the future, the impact of the No. 4 and No. 5 FCCU Turnaround projects will be to increase conversion and not to increase unit feed rates. As such, No. 4 FCCU feed heater H-6151 and No. 5 FCCU feed heater H-5002 are not included as associated heaters.

[8] "No EPA Action Required – Confirmation of FCCU NOx emission Limits, United States of America v. Conoco Inc., Civil Action No. H-01-4430 – ConocoPhillips Ponca City No. 5 FCCU, Ponca City, Oklahoma" from Mr. Tim Goedeker, ConocoPhillips, to Mr. Patrick Foley, United States Environmental Protection Agency, et al, dated February 24, 2010.

No additional heat input will be required for the No. 1 CTU Diesel Recovery Improvement project. As such, No. 1 CTU process heaters H-0001, H-0005, and H-0016 are not included as associated heaters.

The No. 8 Hydrotreater (HDT), No. 9 HDT, No. 1 Hydrogen (H_2) Plant and No. 2 H_2 Plant heaters (see Table III-1 above) were all designed to provide the heat input required at the end of the associated unit's catalyst life, commonly referred to as end-of-run. The HDT and H_2 Plant catalysts have not been to true end-of-run since the units began operation. The original design for the No. 8 HDT catalyst assumed that the catalyst run length would be 5 years. Following initial startup in late 2003[9], the unit ran for 3 years until late 2006 when it was shut down during a No. 5 FCCU turnaround and the HDT catalyst was changed out. The No. 8 HDT catalyst will be changed out again during the 2010 No. 4 FCCU turnaround after only a 4 year run. After that, the No. 8 HDT catalyst will not be changed out until the next FCCU turnaround, which is planned to be in 2015. As such, the No. 8 HDT heaters, H-8601 and H-8602 have not yet operated at end-of run fired duties/capacities, but will do so within the next 5 to 6 years.

The original design for the No. 9 HDT assumed that the catalyst run length would be 18 to 24 months. However, following startup in early 2006[10], deactivation of the catalyst has been much slower than anticipated and end-of-run is not expected to occur until 2012. At that time, the No. 9 HDT heaters, H-9901 and H-9902, are expected to operate at end-of-run fired duties/capacities.

Lastly, the original designs for the No. 1 and No. 2 H_2 Plants assumed that the catalyst run length would be 10 years. Initial startup for the No. 1 and No. 2 H_2 Plants were late 2003[11] and the first part of 2006[12], respectively. As such, catalyst end-of-run for the units is not expected to occur until 2013 for the No. 1 H_2 Plant and 2016 for the No. 2 H_2 Plant. Therefore, like the No. 8 and No. 9 HDTs, the two H_2 Plants and their associated process heaters have not yet operated at end-of-run conditions, but will do so during the next 5 to 6 years.

Per the preceding, the projected actual fired duties/capacities for the No. 8 HDT, No. 9 HDT, No. 1 H_2 Plant and No. 2 H_2 Plant heaters are the expected end-of-run fired duties, which are summarized in Table III-3 along with the maximum design capacities for the heater burners.

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[9] "Gasoline Clean Fuels Projects NSPS Startup Notification – Construction permit No. 2001-194-C (M-1) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated 12/3/03.

[10] "Process Heaters H-9901 and H-9902 NSPS and NESHAP Startup Notification – Construction permit No. 2003-336-C (M-1) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, et al dated 4/17/06.

[11] "Gasoline Clean Fuels Projects NSPS Startup Notification – Construction permit No. 2001-194-C (M-1) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated 12/3/03.

[12] "Process Heater H-9851 NSPS and NESHAP Startup Notification – Construction permit No. 2003-336-C (M-1) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, et al dated 3/6/06.

TABLE III-3. PROJECTED ACTUAL CAPACITIES OF ASSOCIATED PROCESS HEATERS

Associated Emission Unit	Heater	Description	Projected Actual Capacity, mmBTU/Hr[1]	Maximum Design Capacity, mmBTU/Hr[1]
No. 8 HDT	H-8601	Splitter Reboiler	120	141
	H-8602	Feed Heater	35	44
No. 1 H2 Plant	H-8801/8802	Reformer	112	135
No. 9 HDT	H-9901	Feed Heater	40	41
	H-9902	Stripper Reboiler	41	51
No. 2 H2 Plant	H-9851	Reformer	276	315

(1) Higher Heating Value (HHV).

Based on this information, the No. 8 HDT, No. 9 HDT, No. 1 H_2 Plant and No. 2 H_2 Plant process heaters were contemplated to operate, designed to operate, and eventually will operate at the projected actual fired duty at some point in the future when the associated catalyst reaches end-of-run, not as the result of the installation of the 2010-2011 Turnaround projects included in this permit application. Therefore, these heaters are excluded from the projected actual emissions calculations per the definition of "projected actual emissions" included in OAC 252:100-8-31 (See section III.1 above), which states"[i]n determining the projected actual emissions […] (before beginning actual construction), the owner or operator of the major stationary source […] shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project, including any increased utilization due to product demand growth".

The projected actual capacities of associated process heater H-7501 of the No. 6 HDT was calculated using the following methodology:

- Calculate the daily fired duties during 2007, 2008, and 2009.
- Calculate the 365-day rolling average fired duties during that same time period.
- Identify the maximum 365-day rolling average fired duty.
- Increase the maximum 365-day rolling average fired duty by 10%.

Table III-4 summarizes the projected actual fired duty/capacity for heater H-7501 estimated using this methodology:

TABLE III-4. PROJECTED ACTUAL CAPACITY OF ASSOCIATED PROCESS HEATER H-7501

Associated Emission Unit	Heater	Description	Projected Actual Capacity, mmBTU/Hr
No. 6 HDT	H-7501	Reactor Charge Heater	30

A review of the daily fired duties for heater H-7501 during the time period of January 1, 2007 through December 31, 2008 shows that it operated at or above the projected actual capacity for the following number of days:

TABLE III-5. NUMBER OF DAYS THAT ASSOCIATED PROCESS HEATERS OPERATED ABOVE PROJECTED ACTUAL CAPACITIES

Heater	Description	Days Above Projected Actual Capacity	
		2007	2008
H-7501	Reactor Charge Heater	3	22

Based on this information, process heater H-7501 can and did accommodate the projected actual capacities during the baseline period of January 1, 2007 through December 31, 2008. Therefore, like the No. 8 HDT, No. 9 HDT, No. 1 H_2 Plant and No. 2 H_2 Plant process heaters, the No. 6 HDT process heater is excluded from the projected actual emissions calculations.

HF Alkylation Unit (Alky) process heater H-0060 was put into operation on March 7, 2009[13], and so there has not been sufficient time to establish the baseline actual emissions for the furnace. Therefore, the baseline actual emissions for H-0060 are assumed to be equal to the future potential emissions and the past-actual-to-projected-actual emissions increases are zero.

Refer to Table A-7 in Appendix A for detailed capacity evaluations.

<u>Associated Emissions Units – Existing Tanks</u>

Emissions from existing tanks are limited to VOCs and so are not included in the NO_X and SO_2 analysis.

<u>CO, VOC and $PM_{10}/PM_{2.5}$ Emissions Increases</u>

As mentioned above, the CO, VOC and $PM_{10}/PM_{2.5}$ emissions increases resulting from the projects included in this permit application were calculated on a pollutant-by-pollutant basis using the actual-to-potential test described in OAC 252:100-8-30(b)(6). [ConocoPhillips has chosen to conservatively assume that all PM_{10} is $PM_{2.5}$. In this permit, "$PM_{2.5}$" includes both filterable ("front half") and condensable ("back half") components of $PM_{2.5}$.] As such, the Refinery will not be subject to the monitoring and recordkeeping requirements of OAC 252:100-8-36.2(c) for CO, VOC and $PM_{10}/PM_{2.5}$.

Table III-6 summarizes the CO, VOC and $PM_{10}/PM_{2.5}$ emission increases for the modified sources.

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[13] "Process Heater H-0060 NSPS and NESHAP Startup Notification – Construction permit No. 2003-336-C (M-3) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, et al dated 3/16/09.

TABLE III-6. SUMMARY OF PROJECT POTENTIAL CO, PM_{10} AND VOC EMISSION INCREASES

PROJECT	MODIFIED SOURCES	CO (TPY)	$PM_{10}/PM_{2.5}$ (TPY)	VOC (TPY)
No. 4 FCC 2010 Turnaround	No. 4 FCCU (Regenerator)	22.5	0.0[1]	1.3
	Fugitives	---	---	0.0
No. 5 FCC 2011 Turnaround	No. 5 FCCU (Regenerator)	7.1	58.5	4.5
	Fugitives	---	---	0.0
No. 1 CTU Diesel Recovery Improvements	Fugitives	---	---	0.0
HF Alky 2011 Turnaround	Fugitives	---	---	0.7
No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT	Fugitives	---	---	0.1
	Total	29.6	58.5	6.6

[1] The No. 4 FCCU wet gas scrubber (WGS) was put into operation on December 6, 2008[14]. At that time, the No. 4 FCCU PM_{10} mass emission limit was reduced from 145 TPY to 73 TPY (non-sulfate PM) and 110 TPY (total PM). Per the definition of "baseline actual emissions" included in OAC 252:100-8-31 (see Section III.1 above), "the [past actual] average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period". Therefore, because the past actual No. 4 FCCU PM_{10} emissions were greater than the current limit (120 TPY in 2007 and 130 TPY in 2008), the baseline PM_{10} actual emissions have been reduced to the current emission limits, and so the past-actual-to-future-potential emissions increases for these pollutants are zero.

Refer to Tables A-1, A-2, A-3, A-4, A-5, A-6, A-8, A-9, A-10, A-11, A-12, and A-15 in Appendix A for detailed CO, $PM_{10}/PM_{2.5}$, and VOC emissions evaluations.

Associated Emission Units

Table 5-7 summarizes the emissions from sources that were not considered in the actual-to-potential emissions netting analysis for the projects included in this permit application because they were relied upon in previously-issued PSD permits. "Previously relied upon" is interpreted to mean that the sources were included in the BACT analysis of the associated PSD permits and that the emission limits established and made enforceable in those permits have not been superseded by less stringent limits.

[14] "No. 4 FCCU Wet Gas Scrubber Startup Notification – ConocoPhillips Company – Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated December 18, 2008.

TABLE III-7. PREVIOUSLY RELIED UPON EMISSIONS

PSD Permit	ID	Description	Pollutants
2001-194-C (M-3) PSD	H-8601	Splitter Reboiler	CO, PM_{10}, VOC
	H-8602	Feed Heater	CO, PM_{10}, VOC
	H-8801/8802	Reformer	CO, PM_{10}, VOC
2003-336-C (M-3) PSD	H-9901	Feed Heater	CO, VOC
	H-9902	Stripper Reboiler	CO, VOC
	H-9851	Reformer	CO, VOC
	H-0060	Depropanizer Reboiler	CO, VOC
	No. 4 FCCU	Regenerator	CO, VOC
	No. 5 FCCU	Regenerator	CO, VOC

Table III-8 summarizes the emissions increases resulting from emissions units that are associated with the projects included in this permit application.

Table III-8. Summary of Project Associated Emission Increases

Source Number	Associated Sources	CO (TPY)	$PM_{10}/PM_{2.5}$ (TPY)	VOC (TPY)
1	H-8601 No. 8 HDT Splitter Reboiler		[2]	[2]
2	H-8602 No. 8 HDT Feed Heater	[2]	[2]	[2]
3	H-8801/8802 No. 1 H2 Plant Reformer	[2]	[2]	[2]
4	H-9901 No. 9 HDT Feed Heater	[3]	0.4	[3]
5	H-9902 No. 9 HDT Stripper Reboiler	[3]	0.7	[3]
6	H-9851 No. 2 H2 Plant Reformer	[3]	1.3	[3]
7	H-7501 No. 6 HDT Reactor Charge Heater	3.7	0.5	0.4
8	H-0060 HF Alky Depropanizer Reboiler	[3]	0.0 [1]	[3]
9	T-125 Finished Diesel	---	---	0.7
10	T-135 Treated Diesel	---	---	1.0
11	T-136 Treated Diesel	---	---	0.9
12	T-151 Finished Gasoline	---	---	4.8
13	T-162 Treated Gasoline	---	---	3.7
14	T-165 Alkylate	---	---	4.4
	Total	3.7	2.9	15.9

[1] H-0060 was put into operation on March 7, 2009, and so there has not been sufficient time to establish the baseline actual emissions. Therefore, the baseline actual emissions are assumed to be equal to the future potential emissions and the past-actual-to-future-potential emissions increases are zero.
[2] Previously relied upon in permit No. 2001-194-C (M-3) PSD.
[3] Previously relied upon in permit No. 2003-336-C (M-3) PSD.

A comparison of past actual emissions and future potential emissions (for CO, VOC and $PM_{10}/PM_{2.5}$) is presented in Table A-11, A-12, A-13, A-14, and A-15 of Appendix A. Table III-9 compares the project emission increases for all pollutants with PSD SERs to determine if further analysis is required.

TABLE III-9. TOTAL PROJECT EMISSION INCREASE FOR PSD REGULATED POLLUTANTS

Pollutant	Significant Emissions Increase Test	Project Emission Rates (tpy)(1)	Associated Emission Rates (tpy)(2)	Total Emission Rates (tpy)	PSD Significant Emission Rate (tpy)	PSD Analysis?
CO	Actual-to-Potential	29.6	3.7	33.3	100	No
$PM_{10}/PM_{2.5}$	Actual-to-Potential	58.5	2.9	61.4	15	Yes
NO_x	Actual-to-Projected Actual	38.0	0.0	38.0	40	No
SO_2	Actual-to-Projected Actual	39.3	0.0	39.3	40	No
VOC	Actual-to-Potential	6.6	15.9	22.5	40	No

1 Tables III-2 and III-6.

2 Table III-8.

As shown in Table III-9, the total project emissions are above the PSD SER for $PM_{10}/PM_{2.5}$. Therefore, a PSD netting analysis based on Steps 2 through 6 of the PSD netting procedure was conducted for this pollutant.

Step 2 – Contemporaneous Period

Definition of Contemporaneous

Emission increases and decreases that are contemporaneous are those that have occurred during the contemporaneous period. According to OAC 252:100-8-31, “contemporaneous” is defined such that:

> “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”.

The Refinery has interpreted the contemporaneous period to be three years prior to start of construction through the start of operation of the final element of the benzene reduction project. Therefore, for this project, the contemporaneous period begins July 1, 2006 and ends December 31, 2011. ConocoPhillips will update the DEQ per OAC 252:100-8-1-4 should this schedule change.

Step 3 – Emission Increases and Decreases During Contemporaneous Period

Contemporaneous emissions increases and decreases are those emissions associated with new construction, physical changes, or changes in the method of operation of one or more sources that begin operation during the contemporaneous period. Contemporaneous emissions decreases are those emissions decreases associated with new construction, physical changes, changes in the method of operation of one or more sources, or reductions in actual emissions from a federally-enforceable emission limit that begin operation during the contemporaneous period.

Contemporaneous emission increases and decreases were determined through a review of the current Refinery permit history and future planned Refinery projects.

Replacement Process Heaters NH-3, NH-4, and NH-5

Refinery Upgrade Projects permit No. 2007-042-C (M-1) (PSD) was issued by ODEQ on September 2, 2009[15]. The permit included removal of 3 existing process heaters, H-3, H-4, and H-5, and installation of 3 replacement heaters, NH-3, NH-4, and NH-5. However, shutdown and replacement of the 3 heaters has been delayed and will occur outside of the contemporaneous period for this permit application. Therefore, only those projects that are scheduled to be installed during the 2010-2011 timeframe will be included in the contemporaneous period for this permit application; specifically:

- ▲ the Bender Conversion project,
- ▲ the Leased Boilers project, including installation of boilers TB-1, TB-2, and TB-3,
- ▲ the No. 1 CTU Sustaining project, excluding replacement of heater H-0005,
- ▲ the No. 4 CTU Revamp project, excluding replacement of heaters H-0003 and H-0004, and
- ▲ the Benzene Reduction project, which includes installation of new heater NH-1.

A summary of the contemporaneous emissions is provided in Table III-10. As further discussed in Step 4, not all emissions changes included in Table III-10 are creditable.

[15] "Permit No. 2007-042-C (M-1) (PSD) – Refinery Upgrade Projects" from Mr. John Howell, Oklahoma Department of Environmental Quality, to Mr. Dave Gamble, ConocoPhillips, dated February 11, 2009.

TABLE III-10. SUMMARY OF CONTEMPORANEOUS EMISSIONS INCREASES AND DECREASES

Year	Description	Emission Increases or Decreases, TPY				
		CO	PM_{10}/ $PM_{2.5}$	NO_X	SO_2	VOC
2006	No. 5 FCCU WGS (1), (2), (3)	---	-159.0	---	---	---
2007	No. 4 CTU/CVU Upgrade (4)	---	---	---	---	9.5
2007	No. 1 CTU H-0001 Jumper (5)	---	---	---	---	0.5
2007	H-0011 Potential Increase (5)	3.8	0.2	3.8	1.9	0.2
2007	H-7501 Potential Increase (5)	1.0	0.6	11.4	4.8	0.5
2007	Coke Pad Potential Increase (5)	---	7.6	---	---	---
2008	Refinery Hydraulic Limits (5)	---	---	---	---	5.0
2008	South Plant Cooling Water Pump (5)	---	2.8	---	---	3.7
2008	No. 4 FCC WGS (5), (9), (10)	---	-15.0	---	---	5.0
2008	Denatured Ethanol Tanks (6)	---	---	---	---	10.7
2008	H-5001 Shutdown (7)	-27.2	-2.5	---	-1.1	-1.8
2008	H-5002 Startup (12)(13)	21.0	3.9	23.1	16.3	2.9
2009	H-0057/0058/0059 Shutdown (7)	-43.2	-3.9	---	-1.4	-2.8
2009	H-0060 Startup (12)(14)	22.4	4.8(15)	28.0	17.4	3.4(15)
2009	Sat Gas Plant Turnaround	16.5	0.4	4.5	7.3	0.3
2009 (8)	Leased Boilers TB-1, TB-2, and TB-3 (11)	49.8	9.3	45.0	0.6	6.6
2010 (8)	Y-7 Replacement (11)	---	2.6	---	---	1.1
2010 (8)	Y-7 Shutdown (7)	---	-2.9	---	---	-15.8
2010 (8)	Benzene Reduction (11)	23.0	4.3	17.3	6.9	30.3
2010 (8)	No. 9 HDT Turnaround	6.2	1.1	14.8	12.0	0.9
2010 (8)	Coker Turnaround	74.1	8.8	38.9	26.8	1.4
2011 (8)	Bender Conversion (11)	---	---	---	---	16.5
2011 (8)	No. 4 CTU Turnaround	22.9	1.4	36.7	17.9	1.0
2010-2011 (8)	No. 1 CTU Sustaining/No. 4 CTU Revamp (11)	---	---	---	---	11.8
2010-2011 (8)	2010-2011 Turnaround Projects	33.3	61.4	38.0(16)	39.3(16)	22.5

1. The No. 5 FCCU WGS began operation on November 23, 2006.

2. The No. 5 FCCU ESNCR was installed and put into operation during the 4th Quarter, 2006.
3. PM_{10} emission reduction (2007 v. 2006) was -171 TPY. The value used here is the estimate included in permit No. 2007-042-C (PSD).
4. 2002-115-AD (M-3).
5. 2007-042-AD (M-1).
6. 91-031-AD (M-3).
7. Average emissions for 2007-2008.
8. Estimated project timing.
9. The No. 4 FCCU WGS began operation on December 6, 2008.
10. PM_{10} emission reduction is post-WGS startup permit limit (110 TPY) v. average emissions for 2007-2008 (125 TPY).
11. 2007-042-C (M-1) PSD.
12. 2003-336-C (M-3) PSD.
13. Heater H-5002 began operation on November 14, 2008[16]. Therefore the emission increases are assumed to be equal to the limits for the heater included in Permit No. 98-104-TV.
14. Heater H-0060 began operation on March 7, 2009[17]. Therefore the emission increases are assumed to be equal to the limits for the heater included in Permit No. 98-104-TV.
15. "Request to Modify Permit No. 98-104-TV – Title V Operating Permit – Ponca City Refinery – Ponca City, Oklahoma" from Mr. Jerry D. Purkaple, ConocoPhillips, to Mr. Phillip Fielder. Oklahoma Department of Environmental Quality, dated June 1, 2009.
16. Actual-to-projected-actual.

Step 4. Creditable Emissions Changes

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

Emission increases and decreases from previously relied upon contemporaneous projects are not creditable towards the proposed projects. Table III-11 includes a summary of the creditable and contemporaneous projects relied upon in the PSD netting for the proposed projects.

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[16] "Process Heater H-5002 NSPS and NESHAP Startup Notification – Construction Permit No. 2003-336-C (M-3) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated November 19, 2008.

[17] "Process Heater H-0060 NSPS and NESHAP Startup Notification – Construction Permit No. 2003-336-C (M-3) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated March 16, 2009.

Table III-11. Evaluation of Contemporaneous and Creditable Projects

Year	Description	Contemporaneous (Y/N)	Creditable (Y/N)
2006	No. 5 FCCU WGS [(1), (2)]	Y	Y ($PM_{10}/PM_{2.5}$)
2007	No. 4 CTU/CVU Upgrade	Y	[(9)]
2007	No. 1 CTU H-0001 Jumper	Y	[(9)]
2007	H-0011 Potential Increase	Y	Y ($PM_{10}/PM_{2.5}$, NO_X, SO_2)
2007	H-7501 Potential Increase	Y	[(3)]
2007	Coke Pad Potential Increase	Y	Y ($PM_{10}/PM_{2.5}$)
2008	Refinery Hydraulic Limits	Y	[(9)]
2008	South Plant Cooling Water Pump	Y	Y ($PM_{10}/PM_{2.5}$)
2008	No. 4 FCC WGS [(1)]	Y	Y ($PM_{10}/PM_{2.5}$)
2008	Denatured Ethanol Tanks	Y	[(9)]
2008	H-5001 Shutdown [(4)]	Y	Y ($PM_{10}/PM_{2.5}$)
2008	H-5002 Startup	Y	Y ($PM_{10}/PM_{2.5}$, NO_X, SO_2)
2009	H-0057/0058/0059 Shutdown [(4)]	Y	Y ($PM_{10}/PM_{2.5}$)
2009	H-0060 Startup	Y	Y (PM_{10}, NO_X, SO_2)
2009	Sat Gas Plant Turnaround	Y	Y ($PM_{10}/PM_{2.5}$, NO_X, SO_2)
2009 [(8)]	Leased Boilers TB-1, TB-2, and TB-3 [(5)]	Y	Y ($PM_{10}/PM_{2.5}$, SO_2)
2010 [(8)]	Y-7 Replacement [(6)]	Y	Y ($PM_{10}/PM_{2.5}$)
2010 [(8)]	Y-7 Shutdown	Y	Y ($PM_{10}/PM_{2.5}$)
2010 [(8)]	Benzene Reduction [(5)]	Y	Y ($PM_{10}/PM_{2.5}$, SO_2)
2010 [(8)]	No. 9 HDT Turnaround	Y	[(7)]
2010 [(8)]	Coker Turnaround	Y	Y ($PM_{10}/PM_{2.5}$, NO_X, SO_2)
2011 [(8)]	Bender Conversion	Y	[(9)]
2011 [(8)]	No. 4 CTU Turnaround	Y	Y ($PM_{10}/PM_{2.5}$, NO_X, SO_2)
2010-2011 [(8)]	No. 1 CTU Sustaining/No. 4 CTU Revamp [(5)]	Y	[(9)]

1. SO_2 emission credits available from startup of the WGS are to be applied toward SO2 reduction activities required by the Consent Decree.
2. NO_X emission credits available from startup of the ESNCR are to be applied toward NO_X reduction activities required by the Consent Decree.
3. This item is not included as a contemporaneous emissions increase because the No. 6 HDT, which includes heater H-7501 is an associated emissions unit for the projects included in this permit application.

4. NO_X and SO_2 emission credits available from shutdown of this equipment are to be applied toward NO_X reduction activities required by the Consent Decree.
5. Only emission of $PM_{10}/PM_{2.5}$, SO_2, and VOC are considered creditable since emissions of CO and NO_X were previously relied upon for Permit No. 2007-042-C (M-1) PSD.
6. Only emission of $PM_{10}/PM_{2.5}$ and VOC are considered creditable since emissions of CO and NO_X were previously relied upon for Permit No. 2007-042-C (M-1) PSD.
7. This item is not included as a contemporaneous emissions increase because the No. 9 HDT, which includes heaters H-9901 and H-9902, is an associated emissions unit for the projects included in this permit application.
8. Estimated project timing.
9. The only creditable emissions for this project are VOCs, which were not significant for the projects included in this permit application and so do not contribute to the netting analysis.

A summary of the contemporaneous and creditable emission increases and decreases is presented in Table III-12.

Table III-12. Summary of Contemporaneous Emission Increases and Decreases

Year	Description	$PM_{10}/PM_{2.5}$ Emission Increases or Decreases (TPY)
2006	No. 5 FCCU WGS [(2)]	-159.0
2007	No. 4 CTU/CVU Upgrade (2002-115-AD (M-3))	---
2007	No. 1 CTU H-0001 Jumper (2007-042-AD (M-1))	---
2007	H-0011 Potential Increase (2007-042-AD (M-1))	0.2
2007	Coke Pad Potential Increase (2007-042-AD (M-1))	7.6
2008	Refinery Hydraulic Limits (2007-042-AD (M-1))	---
2008	South Plant Cooling Water Pump (2007-042-AD (M-1))	2.8
2008	No. 4 FCC WGS (2007-042-AD (M-1)) [(3)]	-15.0
2008	Denatured Ethanol Tanks (91-031-AD (M-3))	---
2008	H-5001 Shutdown [(4)]	-2.5
2008	H-5002 Startup [(5)]	3.9
2009	H-0057/0058/0059 Shutdown [(4)]	-3.9
2009	H-0060 Startup [(6)]	4.8[(7)]
2009	Sat Gas Plant Turnaround	0.4
2009 [(1)]	Leased Boilers TB-1, TB-2, and TB-3	9.3
2010 [(1)]	Y-7 Replacement	2.6
2010 [(1)]	Y-7 Shutdown	-2.9
2010 [(1)]	Benzene Reduction	4.3
2010 [(1)]	Coker Turnaround	8.8
2011 [(1)]	Bender Conversion	---
2011 [(1)]	No. 4 CTU Turnaround	1.4
2010-2011 [(1)]	No. 1 CTU Sustaining/No. 4 CTU Revamp	---
	Total	-137.2

1. Estimated project timing.
2. No. 5 FCCU $PM_{10}/PM_{2.5}$ emission reduction following startup of the WGS (2007 v. 2006) was -171 TPY. The value used in this analysis is the estimate included in Permit No. 2007-042-C (M-1) PSD.
3. No. 4 FCCU $PM_{10}/PM_{2.5}$ emission reduction value used in this analysis is the Post-WGS startup permit limit (110 TPY as per Permit No. 98-104-TV) v. the 2007/2008 average (125 TPY).
4. Credit values are 2007/2008 averages.

5. Heater H-5002 began operation on November 14, 2008[18]. Therefore the emission increases are assumed to be equal to the limits for the heater included in Permit No. 98-104-TV.
6. Heater H-0060 began operation on March 7, 2009[19]. Therefore the emission increases are assumed to be equal to the limits for the heater included in Permit No. 98-104-TV.
7. "Request to Modify Permit No. 98-104-TV – Title V Operating Permit – Ponca City Refinery – Ponca City, Oklahoma" from Mr. Jerry D. Purkaple, ConocoPhillips, to Mr. Phillip Fielder. Oklahoma Department of Environmental Quality, dated June 1, 2009.

Step 5. Net Project Emission Increases

Table III-13 summarizes the net emissions increases and decreases from the project.

TABLE III-13. NET EMISSIONS INCREASES FROM THE PROJECT

Pollutant	Project Related Increases (tpy)[(1)]	Creditable Contemporaneous Emissions (tpy)[(2)]	Net Emission Increases (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review?
CO	NA	NA	NA	NA	NA
$PM_{10}/PM_{2.5}$	61.4	-137.2	**-75.8**	15	No
NO_x	NA	NA	**NA**	NA	NA
SO_2	NA	NA	**NA**	NA	NA
VOC	NA	NA	**NA**	NA	NA

1 Table III-9.
2 Table III-12.

Step 6. PSD Review

The projects included in this permit application are subject to PSD review for each regulated pollutant for which the sum of all creditable emissions increases and decreases results in a significant net emissions increase. Because the emissions increase for $PM_{10}/PM_{2.5}$ was not significant, a PSD review analysis is not required for the pollutant.

SECTION IV. Oklahoma Air Pollution Control Rules

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

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[18] "Process Heater H-5002 NSPS and NESHAP Startup Notification – Construction Permit No. 2003-336-C (M-3) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated November 19, 2008.

[19] "Process Heater H-0060 NSPS and NESHAP Startup Notification – Construction Permit No. 2003-336-C (M-3) PSD – ConocoPhillips Company, Ponca City Refinery" from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated March 16, 2009.

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. The primary standards are enumerated in Appendix E and the secondary standards are enumerated in Appendix F of the Air Pollution Control Rules (OAC 252:100). National Ambient Air Quality Standards (NAAQS) are established by the U.S. EPA. The actual ambient air concentrations of criteria pollutants are monitored within the State of Oklahoma by DEQ Air Quality Division. At this time, all of Oklahoma is in "attainment" of these standards. The air quality analysis confirms that the project will not cause a violation of the NAAQS.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division (AQD). Emission inventories have been 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]
<u>Part 3</u> summarizes permit application fees for Part 70 source permits. The required construction permit fee of $1,500 has been submitted.

<u>Part 5</u> includes the general administrative requirements for Part 70 permits. A construction permit is required for any planned changes in the operation of the facility, which would require a modification of a Part 70 permit. Such changes include projects that cannot be defined as "Insignificant Activities" or "Trivial Activities," and are not authorized in a current state permit. Insignificant activities mean individual emission units, to which a state or federal requirement does not apply, that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

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

Trivial activities are any individual or combination of air emissions units that are considered inconsequential and are on a list approved by the Administrator and contained in Appendix J. After construction, the operating permit for this modification will be incorporated into the facility's initial Part 70 permit application.

<u>Part 7</u> covers the PSD requirements for attainment areas. Emissions increases resulting from the projects included in this permit application were calculated on a pollutant-by-pollutant basis using the actual-to-

projected-actual test described in OAC 252:100-8-30(b)(3) for NO_X and SO_2 and the actual-to-potential test described in OAC 252:100-8-30(b)(6) for CO, VOC, and PM_{10}. As such, the Refinery will be subject to the monitoring and recordkeeping requirements of OAC 252:100-8-36.2(c)(3) for NO_X and SO_2. Because the projects will not increase the design capacity or potential to emit of any of the modified or associated sources, the monitoring and recordkeeping required by OAC 252:100-8-36.2(c)(3) must be maintained for 5 years following resumption of regular operations after completion of the proposed projects.

OAC 252:100-9 (Excess Emission and Malfunction Reporting Requirements) [Applicable]

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

OAC 252:100-13 (Open Burning) [Applicable]

Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this Subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]

This subchapter specifies particulate emission limits for fuel-burning equipment and industrial processes. Indirect-fired equipment includes process heaters and steam boilers. Industrial processes at the facility are fluid catalytic cracking unit regenerators, cooling towers, and coke loading facility. The following table compares allowable PM emissions to actual or calculated emissions. All units are in compliance with Subchapter 19. Applicable limitations from this subchapter are incorporated into the Ponca City Refinery Title V permit under individual Emission Unit Groups.

TABLE IV-1. COMPARISON OF PM EMISSIONS TO ALLOWABLE EMISSION RATES UNDER OAC 252:100 APPENDIX G

Unit	Process Weight TPH (1)	Allowable PM Emissions, Lbs/Hr (2)	Actual PM Emission Rate, Lbs/Hr	Permitted PM Emission Rate, TPY (Lbs/Hr)
No. 4 FCCU	970 (3)	77.2	1.6 (3)	110 (25.1)
No. 5 FCCU	1,677 (4)	84.5	13.2 (4)	131 (29.9)

1. The process weight for an FCCU is the catalyst circulation rates measured during stack testing.
2. Allowable Particulate Emission Rates calculated using formula include in Appendix G of OAC 252:100 – $E = 55.0 * P^{0.11} - 40$ where E is the allowable emission rate in lbs/hr and P is the process weight in tons/hr.
3. No. 4 FCCU stack performance test – March 18, 2009.
4. No. 5 FCCU stack performance test – August 15, 2007

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]

No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. An alternate monitoring method approval request was submitted to EPA on May 16, 2007 and updated on May 5, 2009, for the No. 4 FCCU in lieu of opacity monitoring, due to the installation of a wet gas scrubber. An alternate monitoring method approval request was submitted to EPA on July 16, 2006 and updated on April 18, 2007 for the No. 5 FCCU in lieu of opacity monitoring, due to the installation of a wet gas scrubber. These alternate methods have been incorporated into the Ponca City Refinery Title V permit.

OAC 252:100-29 (Fugitive Dust) [Applicable]

This subpart prohibits the handling, transportation, or disposition of any substance likely to become airborne or windborne without taking "reasonable precautions" to minimize emissions of fugitive dust. No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Measures that may be taken at the facility as necessary to reduce dust are watering of dirt roads, stockpiles, and transport loads, and planting of vegetation. These measures achieve compliance with the "reasonable precautions" requirement. No activities are expected that would produce fugitive dust.

OAC 252:100-31 (Sulfur Compounds) [Applicable]

Part 2 addresses equipment standards for emissions of sulfur oxides and hydrogen sulfide. The SO_2 standards are applicable to all existing sources and new petroleum and natural gas sources subject to Section 26(a)(1). The projects included in this permit application do not result in an increase in H_2S emissions.

Part 5, Section 25 limits sulfur dioxide emissions from new petroleum or natural gas process equipment (constructed or modified after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBtu heat input averaged over 3 hours. This section is not applicable because the projects included in this permit application do not involve modification of fuel-fired equipment.

Part 5, Section 26 addresses equipment standards for emissions of H_2S. No person shall cause, let suffer, or allow any emission of H_2S from any new petroleum or natural gas process equipment without removal of the H_2S from the exhaust gas or oxidizing it to SO_2. Efficiency of removal shall be at least 95%. The projects included in this permit application do not involve any source with significant emissions of H_2S.

OAC 252:100-33 (Nitrogen Oxides) [Not Applicable]

This subchapter prohibits nitrogen oxide emissions calculated as nitrogen dioxide from any gas-fired fuel-burning equipment constructed, altered, replaced, or rebuilt after February 14, 1972 and with a rated heat input of 50 MMBTU/hr or greater in excess of 0.20 lb/MMBTU, three-hour average. This section is not applicable because the projects included in this permit application do not involve modification of fuel-fired equipment.

OAC 252:100-35 (Carbon Monoxide) [Applicable]

Subchapter 35 affects petroleum catalytic cracking units and catalytic reforming units installed or modified on or after July 1, 1972. The No. 4 FCCU was built in 1951 and not modified as to increase the CO emissions thereafter. The No. 5 FCCU was built in 1952, but modifications occurring between 1972 and 1973 increased CO emissions; therefore, Subchapter 35 applies to the No. 5 FCCU. Subchapter 35 requires “complete” secondary combustion, which is defined in the rule as removal of 93% or more of the CO generated. AP-42 Table 5.1-1 (01/95) specifies uncontrolled FCCU CO emissions of 13,700 lb/Mbbl. No. 5 FCCU stack is continuously monitored for CO which shows that the average CO emission for the unit since July 1, 2004 was 6.5 lbs/Mbbl, resulting in a 99.95% reduction of CO, and the maximum 1-day average was 413 lbs/Mbbl, resulting is a 96.98% reduction of CO. Testing of the No. 5 FCCU (Feb. 1998) showed CO emissions of 2.9 lb/Mbbl, or a 99.9% reduction in CO. Applicable requirements from this subchapter are incorporated into the Ponca City Refinery Title V permit for the No. 5 FCCU.

OAC 252:100-37 (Volatile Organic Compounds) [Not Applicable]

Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Part 3 also requires storage tanks constructed after December 28, 1974, with a capacity of more than 40,000 gallons and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a either an external floating roof, a fixed roof with an internal floating cover, a vapor recovery system, or other equally effective control methods approved by the DEQ. Tanks subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements. No new storage tanks will be constructed as part of the projects included in this permit application.

Part 5 limits the VOC content of paints and coatings. There will be no surface coating operations associated with the projects included in this permit application.

Part 7 requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. Section 35(b) 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. Section 36 requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. Section 38 limits VOC emissions from pumps and compressors by specifying specific design and drain recovery system emission requirements. The projects included in this permit application do not include any of the equipment regulated by this part.

OAC 252:100-39 (VOCs in Nonattainment and Former Nonattainment Areas) [Not Applicable]
The Refinery is not located in Tulsa or Oklahoma Counties.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Not 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 V. Federal Regulations

PSD, 40 CFR Part 52 [Not Applicable]
PSD does not apply to this project because the total pollutant-by-pollutant emission rates are less than the corresponding significance levels.

NSPS 40 CFR Part 60 [Subparts A, J, and GGGa are Applicable]
Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected sources, which, for the projects included in this permit application, are fluid catalytic cracking units, new fugitive sources and a replacement storage tank. 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 J, Petroleum Refineries. This subpart, which was amended on June 24, 2008, affects the following facilities in petroleum refineries: fluid catalytic cracking unit (FCCU) 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 FCCU emission limits for carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM), and opacity and requires monitoring of these same emissions. Subpart J also includes testing, reporting, and recordkeeping requirements. The No. 4 and No. 5 FCCUs are both subject to and in compliance with the requirements of Subpart J. No other sources that are subject or potentially subject to Subpart J, specifically fuel gas combustion devices and Clause sulfur recovery plants, will be constructed, reconstructed, or modified by the projects included in this permit application.

Subpart Ja, Petroleum Refineries. As approved on June 24, 2008, the provisions of Subpart Ja apply to fluid catalytic cracking units (FCCUs), fluid coking units (FCUs), 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)). On December 22, 2008 (See Federal Register/ Vol. 73, No.246/ Monday, December 22, 2008/ Proposed Rules) EPA issued a proposed rule to extend the stay. EPA stated that if they “receive[d] no adverse comment, [then EPA would] not take further action on [the] proposed rule”. Also on December 22, 2008, (See Federal Register/ Vol. 73, No.246/ Monday, December 22, 2008/ Rules and Regulations) EPA issued an interim final rule to extend the stay for 60 days beginning December 26, 2008, and a direct final rule to extend the stay, beginning February 24, 2009, until a final decision is reached regarding the issues surrounding the Subpart. Lastly, on December 22, 2008 (See Federal Register/ Vol. 73, No.246/ Monday, December 22, 2008/ Proposed Rules) EPA issued proposed amendments to the June 24, 2008 NSPS, including revised emissions limitations for process heaters and work practice standards for flares. These amendments have not been finalized as of the date of this submission.

The No. 4 FCCU 2010 Turnaround project will include the following project related to the “fluid catalytic cracking unit” as defined in 40 CFR §60.101a:

▲ Reactor cyclone dipleg replacement

The reactor cyclone diplegs are being replaced to reduce particulate matter emissions resulting from dipleg plugging during unit startup and shutdown (See Section II).

The No. 4 FCCU is equipped with a wet gas scrubber (WGS), which began operation on

December 6, 2008[20], that controls PM and SO_2 emissions. As such, No. 4 FCCU PM and SO_2 emissions are primarily a function of the WGS operation, not of the regenerator. Because none of the No. 4 FCCU 2010 Turnaround projects will affect the WGS or its operation, no emission increases are expected to occur. Therefore, because the No. 4 FCCU 2010 Turnaround projects related to the fluid catalytic cracking unit will not result in an increase in the emission rates of PM, SO2, CO, or NOx, they are not a modification under 40 CFR Part 60, and so will not trigger NSPS Ja applicability for the unit.

The estimated cost for the No. 4 FCCU 2010 Turnaround projects related to the fluid catalytic cracking unit is approximately $3,100,000. The estimated cost to construct a comparable new FCCU as defined in 40 CFR §60.101a is approximately $96,000,000. As such, because the cost is less than 50% of the cost required to construct a new facility, the No. 4 FCCU 2010 Turnaround projects related to the fluid catalytic cracking unit are not a reconstruction under 40 CFR Part 60, and so the unit will not be subject to NSPS Subpart Ja.

The remaining No. 4 FCCU 2010 Turnaround project, specifically:

▲ Main frac. column overhead air cooler replacement

(See Section II) is not a modification of the “fluid catalytic cracking unit” as defined in 40 CFR §60.101a. Therefore, it will not trigger NSPS Ja applicability for the unit.

The No. 5 FCCU 2011 Turnaround project will include the following projects related to the “fluid catalytic cracking unit” as defined in 40 CFR §60.101a:

▲ Reactor cyclone replacement
▲ Catalyst stripper internals replacement
▲ Riser replacement

The reactor cyclone replacement project is intended to improve equipment reliability and reduce over-cracking and dry-gas make and increase liquid yields by replacing the existing equipment with the ConocoPhillips best practice riser termination device. (See Section II). The project will not result in increased No. 5 FCCU emissions.

The catalyst stripper internals replacement project is intended to improve hydrocarbon removal from the FCCU catalyst and reduce the regenerator catalyst bed temperature (See Section II). The reduced catalyst bed temperature will, in turn, result in improved unit conversion. The project will not result in increased No. 5 FCCU emissions.

Lastly, the riser replacement project, like the cyclone replacement project, is intended to improve equipment reliability and increase unit conversion (See Section II). While repair of the existing equipment is possible, the length of the riser will need to be extended in order to accommodate

[20] “No. 4 FCCU Wet Gas Scrubber Startup Notification – ConocoPhillips Company – Ponca City Refinery” from Mr. Dave H. Gamble, ConocoPhillips, to Mr. Eddie Terrill, Oklahoma Department of Environmental Quality, dated December 18, 2008.

the reactor cyclone replacement project. As such, complete replacement of the riser is a more cost effective option. As with the other two projects related to the fluid catalytic cracking unit, the riser replacement project will not result in increased No. 5 FCCU emissions.

Because the No. 5 FCCU 2011 Turnaround projects related to the fluid catalytic cracking unit will not result in an increase in the emission rates of PM, SO_2, CO, or NOx as described above, they are not a modification under 40 CFR Part 60, and so will not trigger NSPS Ja applicability for the unit.

The estimated cost for the No. 5 FCCU 2011 Turnaround projects related to the fluid catalytic cracking unit is approximately $35,000,000. The estimated cost to construct a comparable new FCCU as defined in 40 CFR §60.101a is approximately $130,000,000 to $140,000,000. As such, because the cost is less than 50% of the cost required to construct a new facility, the No. 5 FCCU 2010 Turnaround projects related to the fluid catalytic cracking unit are not a reconstruction under 40 CFR Part 60, and so the unit will not be subject to NSPS Subpart Ja.

None of the projects included in this permit application will include new or replacement of existing pressure relief valves (PRVs). Also, the projects included in this permit application are not projected to have an increase in malfunction events resulting in releases at any of the refinery flares. Therefore, the projects included in this permit application will not trigger Subpart Ja applicability for any of the refinery flares.

Subpart Kb, Volatile Organic Liquids Storage Vessels. This subpart affects volatile organic liquid (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. Subpart Kb provides design standards along with monitoring, reporting, and recordkeeping requirements for storage tanks in volatile organic liquid service. In addition, 40 CFR 60.112b specifies that vessels with a design capacity greater than or equal to 39,980 gallons containing a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 0.75 psia but less than 11 psia shall have one of the following vapor control devices: an external fixed roof in combination with an internal floating roof; an external floating roof; a closed vent system to a control device (flare, condenser, or absorber); or an equivalent system. There are no new storage tanks proposed for the projects included in this permit application.

Subpart GGGa, Equipment Leaks of VOC in Petroleum Refineries. Subpart GGG affects each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service which commenced construction, reconstruction, or modification after November 7, 2006 and which is located within a process unit in a petroleum refinery. The subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." The new components are subject to this subpart. The components will be incorporated into the facility's existing LDAR program.

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. The projects included in this permit application will not involve physical changes to individual drain systems.

NESHAP 40 CFR Part 61 **[Not Applicable]**

There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride, except for 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 the projects included in this permit application will be less than 10% by weight and are not intended to operate in benzene service. Therefore, Subpart J is not applicable to these projects.

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 projects included in this permit application will not produce any waste streams with benzene concentrations greater than 10 ppmw. Therefore, the equipment installed per the projects included in this permit application are not subject to Subpart FF.

NESHAP 40 CFR Part 63 **[Subparts CC and UUU are 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 contact 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
- storage vessels and equipment leaks associated with bulk gasoline terminals and pipeline breakout stations at a refinery
- heat exchange systems associated with petroleum refining process units

This project involves the construction of equipment leak components. New valves and associated components 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 Ponca City Refinery Title V permit. The projects included in this permit application will not 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. The projects included in this permit application do 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 the projects included in this permit application. Therefore, this subpart is not applicable.

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.

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 Section 112(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. There are no new or reconstructed boilers and process heaters fired with solid, liquid, and gaseous fuels included in the projects included in this permit application. Therefore, this subpart is not applicable.

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.

Facilities that submit Title V permit applications prior to April 20, 1998 are not subject to CAM until the next Title V permit renewal or Title V permit significant modification. The Ponca City Refinerys original application was received on March 24, 1998.

No. 4 and No. 5 FCCU NOx and SO_2 emissions meet CAM applicability criteria, but are exempt from CAM until the time when the Ponca City Refinery Title V permit is due for renewal. However, because the Title V permit specifies NOx and SO_2 monitoring provisions meeting the definition of continuous compliance determination methods in 40 CFR Subpart 64.1, the No. 4 and No. 5 FCCU NOx and SO_2 emissions are exempt from the CAM rule. With regards to particulate matter (PM) and carbon monoxide (CO), the No. 4 and No. 5 FCCUs are exempt from the CAM rule because the units are both subject to and in compliance with NESHAP Part 63, Subpart UUU for organic HAPs (CO serves as a surrogate measure of the total emissions of organic HAPs) and metal HAPs (PM serves as a surrogate measure of the total emissions of particulate matter and metal HAP contained in the particulate matter, including but not limited to: antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium).

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.

SECTION VI. COMPLIANCE

Tier Classification and Public Review

This application has been determined to be Tier II based on the request for 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 June 6, 2010. 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 will be 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 will be sent to EPA Region VI for a 45-day review period.

The facility is located within 50 miles of the border of Kansas and Oklahoma. A letter will be 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 construction permit to modify a Part 70 source has been paid.

SECTION VII. 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, contingent upon public and EPA review.

Appendix A

Table A-1. No. 4 FCCU Turnaround Project Components

Type of Component	Number of Components	Emission Factor, lb/hr-source[1]	VOC Emissions, lb/hr	VOC Emissions, tons/yr
GGG Components Added :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	0	0.00468	0.000	0.00
Heavy liquid valves	0	0.00051	0.000	0.00
Flanges	0	0.00013	0.000	0.00
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Overall Emissions Increase			**0.000**	**0.00**
GGG Components Removed :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	0	0.00468	0.000	0.00
Heavy liquid valves	0	0.00051	0.000	0.00
Flanges[2]	0	0.00013	0.000	0.00
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare[3]	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Removed [4]:				
Process drains (controlled)	0	0.03500	0.000	0.00
Process drains (uncontrolled)	0	0.07000	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Junction boxes (uncontrolled)	0	0.47000	0.000	0.00
Overall Emissions Decrease			**0.000**	**0.00**
GGG Net Emissions Change			0.000	0.00
QQQ Net Emissions Change			0.000	0.00
Overall Net Emissions Change			**0.000**	**0.00**

Notes:

1. The emission factors are the "permit quality" emission factors for new sources at the Ponca City Refinery referenced in the March 1, 1991 and March 19, 1991 correspondences to Oklahoma Air Quality Service.
2. Assuming an average of 3.6 flanges per valve.
3. The flare control efficiency is assumed to be 98%.
4. Sewer component factors are from AP-42 Fourth Edition, September 1985 and "VOC Emissions from Petroleum Refinery Wastewater Systems - Background Information for Proposed Standards", EPA-450/3-85-001a, Feb. 1985

Table A-2. No. 5 FCCU Turnaround Project Components

Type of Component	Number of Components	Emission Factor, lb/hr-source[1]	VOC Emissions, lb/hr	VOC Emissions, tons/yr
GGG Components Added :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	0	0.00468	0.000	0.00
Heavy liquid valves	0	0.00051	0.000	0.00
Flanges	0	0.00013	0.000	0.00
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Overall Emissions Increase			**0.000**	**0.00**
GGG Components Removed :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	0	0.00468	0.000	0.00
Heavy liquid valves	0	0.00051	0.000	0.00
Flanges[2]	0	0.00013	0.000	0.00
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare[3]	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Removed [4]:				
Process drains (controlled)	0	0.03500	0.000	0.00
Process drains (uncontrolled)	0	0.07000	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Junction boxes (uncontrolled)	0	0.47000	0.000	0.00
Overall Emissions Decrease			**0.000**	**0.00**
GGG Net Emissions Change			0.000	0.00
QQQ Net Emissions Change			0.000	0.00
Overall Net Emissions Change			**0.000**	**0.00**

Notes:

1. The emission factors are the "permit quality" emission factors for new sources at the Ponca City Refinery referenced in the March 1, 1991 and March 19, 1991 correspondences to Oklahoma Air Quality Service.
2. Assuming an average of 3.6 flanges per valve.
3. The flare control efficiency is assumed to be 98%.
4. Sewer component factors are from AP-42 Fourth Edition, September 1985 and "VOC Emissions from Petroleum Refinery Wastewater Systems - Background Information for Proposed Standards", EPA-450/3-85-001a, Feb. 1985

Table A-3. HF Alky Turnaround Project Components

Type of Component	Number of Components	Emission Factor, lb/hr-source[1]	VOC Emissions, lb/hr	VOC Emissions, tons/yr
GGG Components Added :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	30	0.00468	0.140	0.61
Heavy liquid valves	0	0.00051	0.000	0.00
Flanges	108	0.00013	0.014	0.06
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Overall Emissions Increase			**0.154**	**0.68**
GGG Components Removed :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	0	0.00468	0.000	0.00
Heavy liquid valves	0	0.00051	0.000	0.00
Flanges[2]	0	0.00013	0.000	0.00
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare[3]	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Removed [4]:				
Process drains (controlled)	0	0.03500	0.000	0.00
Process drains (uncontrolled)	0	0.07000	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Junction boxes (uncontrolled)	0	0.47000	0.000	0.00
Overall Emissions Decrease			**0.000**	**0.00**
GGG Net Emissions Change			0.154	0.68
QQQ Net Emissions Change			0.000	0.00
Overall Net Emissions Change			**0.154**	**0.68**

Notes:

1. The emission factors are the "permit quality" emission factors for new sources at the Ponca City Refinery referenced in the March 1, 1991 and March 19, 1991 correspondences to Oklahoma Air Quality Service.
2. Assuming an average of 3.6 flanges per valve.
3. The flare control efficiency is assumed to be 98%.
4. Sewer component factors are from AP-42 Fourth Edition, September 1985 and "VOC Emissions from Petroleum
Refinery Wastewater Systems - Background Information for Proposed Standards", EPA-450/3-85-001a, Feb. 1985

Table A-4. No. 1 CTU Diesel Recovery Improvements Project Components

Type of Component	Number of Components	Emission Factor, lb/hr-source[1]	VOC Emissions, lb/hr	VOC Emissions, tons/yr
GGG Components Added :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	0	0.00468	0.000	0.00
Heavy liquid valves	2	0.00051	0.001	0.00
Flanges	6	0.00013	0.001	0.00
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Overall Emissions Increase			**0.002**	**0.01**
GGG Components Removed :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	0	0.00468	0.000	0.00
Heavy liquid valves	3	0.00051	0.002	0.01
Flanges	10	0.00013	0.001	0.01
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Removed [4]:				
Process drains (controlled)	0	0.03500	0.000	0.00
Process drains (uncontrolled)	0	0.07000	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Junction boxes (uncontrolled)	0	0.47000	0.000	0.00
Overall Emissions Decrease			**-0.003**	**-0.01**
GGG Net Emissions Change			-0.001	0.00
QQQ Net Emissions Change			0.000	0.00
Overall Net Emissions Change			**-0.001**	**0.00**

Notes:

1. The emission factors are the "permit quality" emission factors for new sources at the Ponca City Refinery referenced in the March 1, 1991 and March 19, 1991 correspondences to Oklahoma Air Quality Service.
2. Reserved.
3. Reserved.
4. Sewer component factors are from AP-42 Fourth Edition, September 1985 and "VOC Emissions from Petroleum Refinery Wastewater Systems - Background Information for Proposed Standards", EPA-450/3-85-001a, Feb. 1985.

Table A-5. No. 6 HDT Unstabilized Naphtha Jumper To No. 9 HDT Project Components

Type of Component	Number of Components	Emission Factor, lb/hr-source[1]	VOC Emissions, lb/hr	VOC Emissions, tons/yr
GGG Components Added :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	4	0.00468	0.019	0.08
Heavy liquid valves	0	0.00051	0.000	0.00
Flanges	14.4	0.00013	0.002	0.01
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Added:				
Process drains (controlled)	0	0.03500	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Overall Emissions Increase			**0.021**	**0.09**
GGG Components Removed :				
Gas valves	0	0.00253	0.000	0.00
Light liquid valves	0	0.00468	0.000	0.00
Heavy liquid valves	0	0.00051	0.000	0.00
Flanges[2]	0	0.00013	0.000	0.00
Light liquid pumps	0	0.04509	0.000	0.00
Heavy liquid pumps	0	0.04718	0.000	0.00
Gas compressors	0	0.50265	0.000	0.00
Gas relief valves to atmosphere	0	0.22928	0.000	0.00
Gas relief valves to flare[3]	0	0.00459	0.000	0.00
Sample Stations	0	0.03307	0.000	0.00
QQQ Components Removed [4]:				
Process drains (controlled)	0	0.03500	0.000	0.00
Process drains (uncontrolled)	0	0.07000	0.000	0.00
Junction (or water draw) boxes (controlled)	0	0.07000	0.000	0.00
Junction boxes (uncontrolled)	0	0.47000	0.000	0.00
Overall Emissions Decrease			**0.000**	**0.00**
GGG Net Emissions Change			0.021	0.09
QQQ Net Emissions Change			0.000	0.00
Overall Net Emissions Change			**0.021**	**0.09**

Notes:

1. The emission factors are the "permit quality" emission factors for new sources at the Ponca City Refinery referenced in the March 1, 1991 and March 19, 1991 correspondences to Oklahoma Air Quality Service.
2. Assuming an average of 3.6 flanges per valve.
3. The flare control efficiency is assumed to be 98%.
4. Sewer component factors are from AP-42 Fourth Edition, September 1985 and "VOC Emissions from Petroleum
Refinery Wastewater Systems - Background Information for Proposed Standards", EPA-450/3-85-001a, Feb. 1985

Table A-6. Associated Process Heater Parameters

EU ID	Unit	Maximum Firing Rate (MMBTU/HR)	Notes	Fuel Gas Heating Value (BTU/SCF)	Flow Rate (MMSCF/HR)	Pollutant	Emission Factor (LB/MMSCF)	Emission Factor (LB/MMBTU)	Notes	Maximum Potential Emissions (LB/HR)	Maximum Potential Emissions (TPY)	Notes	Maximum Hours Operation (HR/YR)
H-0060	*Associated Heater* Alky Depropanizer Reboiler	147.0	G	867	0.170	CO	--	0.0350	G	5.11	22.4	E	8760
						$PM_{10}/PM_{2.5}$	7.6	0.0075	B	1.10	4.8	G	
						NO_x	--	0.0430	G	6.39	28.0	E	
						SO_2	--	0.0270	G	3.97	17.4	E	
						VOC	5.5	0.0054	B	0.78	3.4	G	
H-7501	*Associated Heater* No. 6 HDT Heater	41.0	E	867	0.047	CO	--	0.0300		1.23	5.4	E	8760
						$PM_{10}/PM_{2.5}$	7.6	0.0075	B	0.30	1.3	E	
						NOx	--	--	--	--	--	C	
						SO2	--	--	--	--	--	C	
						VOC	5.5	0.0056	B	0.23	1.0	E	
H-8601	*Associated Heater* *r* No. 8 HDT Splitter Reboiler	120.0	E	867	0.138	CO	84	0.0820	B	9.89	43.3	E	8760
						$PM_{10}/PM_{2.5}$	7.6	0.0075	B	0.89	3.9	E	
						NO_x	--	--	--	--	--	C	
						SO_2	--	--	--	--	--	C	
						VOC	5.5	0.0054	B	0.66	2.9	E	
H-8602	*Associated Heater* No. 8 HDT Feed Heater	36.0	E	867	0.042	CO	84	0.0820	B	2.97	13.0	E	8760
						$PM_{10}/PM_{2.5}$	7.6	0.0075	B	0.27	1.2	E	
						NO_x	--	--	--	--	--	C	
						SO_2	--	--	--	--	--	C	
						VOC	5.5	0.0054	B	0.18	0.8	E	
H-8801/8802	*Associated Heater* No. 1 Hydrogen Planr Reformer	123.0	E	867	0.142	CO	84	0.0820	B	10.09	44.2	E	8760
						$PM_{10}/PM_{2.5}$	7.6	0.0075	B	0.91	4.0	E	
						NO_x	--	--	--	--	--	C	
						SO_2	--	--	--	--	--	C	
						VOC	5.5	0.0054	B	0.66	2.9	E	

Table A-6. Associated Process Heater Parameters [Continued]

H-9901	*Associated Heater* No. 9 HDT Charge Heater	40.0	E	867	0.046	CO	--	0.0400		1.60	7.0	E	8760
						$PM_{10}/PM_{2.5}$	7.6	0.0075	B	0.30	1.3	E	
						NOx	--	--	--	--	--	C	
						SO2	--	--	--	--	--	C	
						VOC	5.5	0.0054	B	0.23	1.0	E	
H-9902	*Associated Heater* No. 9 HDT Stripper Reboiler	50.0	E	867	0.058	CO	--	0.0400		2.01	8.8	E	8760
						$PM_{10}/PM_{2.5}$	7.6	0.0075	B	0.37	1.6	E	
						NOx	--	--	--	--	--	C	
						SO2	--	--	--	--	--	C	
						VOC	5.5	0.0054	B	0.27	1.2	E	
H-9851	*Associated Heater* No. 2 Hydrogen Plant Reformer	282.0	E	867	0.325	CO	--	0.0400		11.30	49.5	E	8760
						PM10	7.6	0.0075	B	2.12	9.3	E	
						NOx	--	--	--	--	--	C	
						SO2	--	--	--	--	--	C	
						VOC	5.5	0.0054	B	1.53	6.7	E	

Notes

[B] Emission factors taken from AP-42 Section 1.4, Tables 1.4-1 and 1.4-2 (July 1998).
[C] NOx and SO2 emissions increases calculated using actual-to-projected-actual test described in OAC 252:100-8-30(b)(3).
[D] Based on NSPS Subpart J allowable sulfur content of 0.10 grains per dry standard cubic foot (160 ppm_v H_2S in fuel gas) and future heating value of fuel gas as determined by ConocoPhillips
[E] Permit No. 98-104-TV
[F] Request to Modify Permit No. 98-104-TV, dated April 24, 2008
[G] Request to Modify Permit No. 98-104-TV, dated June 1, 2009

Table A-7. Associated Process Heater Capacities/Fired Duties

Heater	Maximum Design Fired Duty (mmBTU/Hr - HHV)	Maximum 365-Day Average Fired Duty (mmBTU/Hr - HHV)	Projected Actual Fired Duty (mmBTU/Hr - HHV)	Days Above Projected Actual Capacity 2007	Days Above Projected Actual Capacity 2008	Notes
H-7501	32	27	30	3	22	a, b
H-8601	141	83	120	NA	NA	a, c
H-8602	44	16	35	NA	NA	a, c
H-8801/8802	135	68	112	NA	NA	a, c
H-9901	41	30	40	NA	NA	a, c
H-9902	51	28	41	NA	NA	a, c
H-9851	315	241	276	NA	NA	a, c

[a] Maximum 365-day average fired duty based on 2007, 2008 and 2009 operation.
[b] Projected actual capacity = (Maximum 365-day Average Fired Duty) x 1.1.
[c] Projected actual capacity based on estimated catalyst end-of-run heat input requirements.

Table A-8. No. 4 FCCU Emissions Summary

Pollutant	2007 Actual Emissions (tpy)	2008 Actual Emissions (tpy)	Average Emissions (tpy)	Future Potential Emissions w/ WGS (tpy)	Projected Actual Emissions w/ WGS (tpy)	Notes
CO	86.76	88.31	87.54	110.00	NA	a
$PM/PM_{10}/PM_{2.5}$	119.62	129.70	124.66	110.00	NA	a, b
NO_X	39.80	36.60	38.20	NA	60.00	d
SO_2	131.13	100.26	115.70	NA	55.00	c, d
VOC	6.51	6.62	6.57	8.3	NA	a

[a] Future potential emissions are per permit No. 98-104-TV.

[b] The No. 4 FCCU wet gas scrubber (WGS) was put into operation on December 6, 2008 . At that time, the No. 4 FCCU PM10 mass emission limit was reduced from 145 TPY to 73 TPY (non-sulfate PM) and 110 TPY (total PM).

[c] The No. 4 FCCU wet gas scrubber (WGS) was put into operation on December 6, 2008 . At that time, the No. 4 FCCU SO2 mass emission limit was reduced from 333 TPY to 55 TPY.

[d] NOx and SO2 emissions increases calculated using actual-to-projected-actual test described in OAC 252:100-8-30(b)(3). No. 4 FCCU SO2 projected actual emissions set equal to permitted emissions per No. 98-104-TV.

Table A-9. No. 5 FCCU Emissions Summary

Pollutant	2007 Actual Emissions (tpy)	2008 Actual Emissions (tpy)	Average Emissions (tpy)	Future Potential Emissions w/ESNCR & WGS (tpy)	Projected Actual Emissions w/ESNCR & WGS (tpy)	Notes
CO	59.78	18.30	39.04	46.10	NA	a
PM/PM_{10}/$PM_{2.5}$	84.28	60.88	72.58	131.00	NA	a
NO_X	96.41	80.49	88.45	NA	105.00	b
SO_2	58.56	54.95	56.76	NA	80.00	b
VOC	5.52	5.39	5.46	10.00	NA	c, d

[a] Future potential emissions are per permit No. 98-104-TV.

[b] NOx and SO2 emissions increases calculated using actual-to-projected-actual test described in OAC 252:100-8-30(b)(3).

[c] No. 5 FCCU currently does not have a VOC emission limit.

[d] See Table A-10.

Table A-10. No. 5 FCCU VOC Future Potential Emission Calculation

Variable	Value	Units	Notes
VOC	2.27	ppmvd @ 0% O2	a
O2	5.00	Vol% (dry basis)	b
VOC (Raw)	1.73	ppmvd	
Flue Gas	165,000	DSCFM	c
VOC	1.96	Lbs/Hr	d
VOC	8.57	TPY	d
VOC	10.00	TPY	d, e

[a] Per March 25, 2008 stack test.

[b] Assumed maximum stack excess oxygen.

[c] Corresponds to 2007-2008 1-day maximum, increased by 10%.

[d] Characterized as propane (C3H8).

[e] Future potential.

Table A-11. Carbon Monoxide Emissions

EU ID	Emission Unit Description	CO Emissions: 2007 Actual Emissions (tpy)	2008 Actual Emissions (tpy)	Avg (tpy)	Future Potential Emissions (tpy)	Increase (tpy)	Decrease (tpy)	Total Δ (tpy)	Notes
	Modified Units								
4 FCCU	No. 4 FCC Regenerator	87.0	88.0	87.5	110.0	22.5	0.0	22.5	
FUG	No. 4 FCC 2010 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
5 FCCU	No. 5 FCC Regenerator	60.0	18.0	39.0	46.1	7.1	0.0	7.1	
FUG	No. 5 FCC 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 1 CTU Diesel Recovery Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	HF Alky 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Associated Units								
H-0060	HF Alky	22.4	22.4	22.4	22.4	0.0	0.0	0.0	*2, 3*
H-7501	No. 6 HDT	1.7	1.7	1.7	5.4	3.7	0.0	3.7	
H-8601	No. 8 HDT	0.0	0.0	0.0	43.3	43.3	0.0	43.3	*1*
H-8602	No. 8 HDT	0.0	0.0	0.0	13.0	13.0	0.0	13.0	*1*
H-8801/8802	No. 1 Hydrogen Plant	4.3	0.0	2.1	44.2	42.1	0.0	42.1	*1*
H-9901	No. 9 HDT	4.7	4.3	4.5	7.0	2.5	0.0	2.5	*2*
H-9902	No. 9 HDT	0.0	4.7	2.4	8.8	6.4	0.0	6.4	*2*
H-9851	No. 2 Hydrogen Plant	2.1	2.1	2.1	49.5	47.4	0.0	47.4	*2*
Tanks	T-125, T-135, T-136, T-151, T-162, T-165	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		TOTAL CO EMISSION INCREASES			33.3				
		Significance level			100.0				
		Significant increase?			NO				

NOTES:

1) Previously relied upon in permit No. 2001-194-C (M-3) PSD and so emission increases are not included in the Total Emission Increases.

2) Previously relied upon in permit No. 2003-336-C (M-3) PSD and so emission increases are not included in the Total Emission Increases.

3) H-0060 was put into operation on March 7, 2009, and so there has not been sufficient time to establish the baseline actual emissions. Therefore, the baseline actual emissions are assumed to be equal to the future potential emissions and the past-actual-to-future-potential emissions increases are zero.

Table A-12. Particulate Matter ($PM_{10}/PM_{2.5}$) Emissions

EU ID	Emission Unit Description	PM_{10} Emissions							
		2007 Actual Emissions (tpy)	2008 Actual Emissions (tpy)	Avg (tpy)	Future Potential Emissions (tpy)	Increase (tpy)	Decrease (tpy)	Total Δ (tpy)	Notes
Modified Units									
4 FCCU	No. 4 FCC Regenerator	120.0	130.0	125.0	110.0	0.0	-15.0	-15.0	
FUG	No. 4 FCC 2010 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
5 FCCU	No. 5 FCC Regenerator	84.0	61.0	72.5	131.0	58.5	0.0	58.5	
FUG	No. 5 FCC 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 1 CTU Diesel Recovery Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	HF Alky 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Associated Units									
H-0060	HF Alky	4.8	4.8	4.8	4.8	0.0	0.0	0.0	*2*
H-7501	No. 6 HDT	0.8	0.8	0.8	1.3	0.5	0.0	0.5	
H-8601	No. 8 HDT	2.7	2.5	2.6	3.9	1.3	0.0	1.3	*1*
H-8602	No. 8 HDT	0.3	0.5	0.4	1.2	0.8	0.0	0.8	*1*
H-8801/8802	No. 1 Hydrogen Plant	2.1	1.9	2.0	4.0	2.0	0.0	2.0	*1*
H-9901	No. 9 HDT	0.8	1.0	0.9	1.3	0.4	0.0	0.4	
H-9902	No. 9 HDT	0.9	0.9	0.9	1.6	0.7	0.0	0.7	
H-9851	No. 2 Hydrogen Plant	8.5	7.5	8.0	9.3	1.3	0.0	1.3	
Tanks	T-125, T-135, T-136, T-151, T-162, T-165	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		TOTAL $PM_{10}/PM_{2.5}$ EMISSION INCREASES							61.4
		Significance level							15.0
		Significant increase?							YES

NOTES:
1) Previously relied upon in permit No. 2001-194-C (M-3) PSD and so emission increases are not included in the Total Emission Increases.
2) H-0060 was put into operation on March 7, 2009, and so there has not been sufficient time to establish the baseline actual emissions. Therefore, the baseline actual emissions are assumed to be equal to the future potential emissions and the past-actual-to-future-potential emissions increases are zero.

Table A-13. Nitrogen Oxide Emissions

EU ID	Emission Unit Description	NO_x Emissions: Actual Emissions (tpy) 2007	Actual Emissions (tpy) 2008	Avg (tpy)	Projected Actual Emissions (tpy)	Increase (tpy)	Decrease (tpy)	Total Δ (tpy)	Notes
Modified Units									
4 FCCU	No. 4 FCC Regenerator	40.0	37.0	38.5	60.0	21.5	0.0	21.5	
FUG	No. 4 FCC 2010 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
5 FCCU	No. 5 FCC Regenerator	96.5	80.5	88.5	105.0	16.5	0.0	16.5	*4*
FUG	No. 5 FCC 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 1 CTU Diesel Recovery Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	HF Alky 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Associated Units									
H-0060	HF Alky	28.0	28.0	28.0	28.0	0.0	0.0	0.0	*1*
H-7501	No. 6 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*2*
H-8601	No. 8 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-8602	No. 8 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-8801/8802	No. 1 Hydrogen Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-9901	No. 9 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-9902	No. 9 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-9851	No. 2 Hydrogen Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
Tanks	T-125, T-135, T-136, T-151, T-162, T-165	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		TOTAL NO_x EMISSION INCREASES							38.0
		Significance level							40.0
		Significant increase?							NO

NOTES:

1) H-0060 was put into operation on March 7, 2009, and so there has not been sufficient time to establish the baseline actual emissions. Therefore, the baseline actual emissions are assumed to be equal to the future potential emissions and the past-actual-to-future-potential emissions increases are zero.

2) Heater accommodated the projected actual capacity during the 2007-2008 baseline period and so is not included in the projected actual emissions calculations per the definition of "projected actual emissions" included in OAC 252:100-8-31

3) Heater capacity designed for catalyst end-of-run conditions which exceeds projected actual capacity. As such, the heater could have accommodated the projected actual capacity during the 2007-2008 baseline period and so is not included in the projected actual emissions calculations per the definition of "projected actual emissions" included in OAC 252:100-8-31.

4) No. 5 FCCU 2007 NOx emissions revised to coincide with the current NOx emission limit of 37.1 ppmvd @ 0% O2, 365-day rolling average basis.

Table A-14. Sulfur Dioxide Emissions

EU ID	Emission Unit Description	SO_2 Emissions: Actual Emissions (tpy) 2007	Actual Emissions (tpy) 2008	Avg (tpy)	Projected Actual Emissions (tpy)	Increase (tpy)	Decrease (tpy)	Total Δ (tpy)	Notes
	Modified Units								
4 FCCU	No. 4 FCC Regenerator	40.1	37.3	38.7	55.0	16.3	0.0	16.3	*4*
FUG	No. 4 FCC 2010 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
5 FCCU	No. 5 FCC Regenerator	59.0	55.0	57.0	80.0	23.0	0.0	23.0	
FUG	No. 5 FCC 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 1 CTU Diesel Recovery Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	HF Alky 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Associated Units								
H-0060	HF Alky	17.4	17.4	17.4	17.4	0.0	0.0	0.0	*1*
H-7501	No. 6 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*2*
H-8601	No. 8 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-8602	No. 8 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-8801; H-8802	No. 1 Hydrogen Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-9901	No. 9 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-9902	No. 9 HDT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
H-9851	No. 2 Hydrogen Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*3*
Tanks	T-125, T-135, T-136, T-151, T-162, T-165	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
		TOTAL SO_2 EMISSION INCREASES							39.3
		Significance level							40.0
		Significant increase?							NO

NOTES:

1) H-0060 was put into operation on March 7, 2009, and so there has not been sufficient time to establish the baseline actual emissions. Therefore, the baseline actual emissions are assumed to be equal to the future potential emissions and the past-actual-to-future-potential emissions increases are zero.

2) Heater accommodated the projected actual capacity during the 2007-2008 baseline period and so is not included in the projected actual emissions calculations per the definition of "projected actual emissions" included in OAC 252:100-8-31

3) Heater capacity designed for catalyst end-of-run conditions which exceeds projected actual capacity. As such, the heater could have accommodated the projected actual capacity during the 2007-2008 baseline period and so is not included in the projected actual emissions calculations per the definition of "projected actual emissions" included in OAC 252:100-8-31.

4) No. 4 FCCU 2007 and 2008 SO2 emissions revised to coincide with the current SO2 emission limit of 25 ppmvd @ 0% O2, 365-day rolling average basis.

Table A-15. Volatile Organic Compound Emissions

EU ID	Emission Unit Description	VOC Emissions: Actual Emissions (tpy) 2007	Actual Emissions (tpy) 2008	Avg (tpy)	Future Potential Emissions (tpy)	Increase (tpy)	Decrease (tpy)	Total Δ (tpy)	Notes
Modified Units									
4 FCCU	No. 4 FCC Regenerator	7.0	7.0	7.0	8.3	1.3	0.0	1.3	
FUG	No. 4 FCC 2010 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
5 FCCU	No. 5 FCC Regenerator	5.5	5.4	5.5	10.0	4.5	0.0	4.5	
FUG	No. 5 FCC 2011 Turnaround Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 1 CTU Diesel Recovery Fug Components	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FUG	No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT Fug Components	0.0	0.0	0.0	0.1	0.1	0.0	0.1	
FUG	HF Alky 2011 Turnaround Fug Components	0.0	0.0	0.0	0.7	0.7	0.0	0.7	
Associated Units									
H-0060	HF Alky	3.4	3.4	3.4	3.4	0.0	0.0	0.0	*2, 3*
H-7501	No. 6 HDT	0.6	0.6	0.6	1.0	0.4	0.0	0.4	
H-8601	No. 8 HDT	2.0	1.8	1.9	2.9	1.0	0.0	1.0	*1*
H-8602	No. 8 HDT	0.2	0.4	0.3	0.8	0.5	0.0	0.5	*1*
H-8801/8802	No. 1 Hydrogen Plant	1.5	1.4	1.4	2.9	1.5	0.0	1.5	*1*
H-9901	No. 9 HDT	0.6	0.7	0.7	1.0	0.3	0.0	0.3	*2*
H-9902	No. 9 HDT	0.6	0.7	0.6	1.2	0.6	0.0	0.6	*2*
H-9851	No. 2 Hydrogen Plant	6.1	5.4	5.8	6.7	0.9	0.0	0.9	*2*
Tanks	T-125, T-135, T-136, T-151, T-162, T-165	0.0	0.0	0.0	15.5	15.5	0.0	15.5	
		TOTAL VOC EMISSION INCREASES							22.5
		Significance level							40.0
		Significant increase?							NO

NOTES:

1) Previously relied upon in permit No. 2001-194-C (M-3) PSD and so emission increases are not included in the Total Emission Increases.

2) Previously relied upon in permit No. 2003-336-C (M-3) PSD and so emission increases are not included in the Total Emission Increases.

3) H-0060 was put into operation on March 7, 2009, and so there has not been sufficient time to establish the baseline actual emissions. Therefore, the baseline actual emissions are assumed to be equal to the future potential emissions and the past-actual-to-future-potential emissions increases are zero.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

ConocoPhillips Company **Permit No. 98-104-C (M-6)**
Ponca City Refinery
Refinery 2010-2011 Turnaround Projects

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on July 7, 2009 and subsequent supplemental information. The Evaluation Memorandum dated June 8, 2010, 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

Emission Unit	Fired Duty Limit mmBTU/Hr(1)	Pollutant	Emissions	
			Lbs/mmBTU(1)	ppmvd @ 3% O2
H-0001 No. 1 CTU Charge Heater	175	NOx	0.060	–
		CO	0.040	–
			0.060(3)	–
			0.080(4)	–
H-0048 No. 2 CRU Reactor Preheater	241.4	NOx	0.070	–
		CO	0.040	–
			0.060(3)	–
			0.080(4)	–
			–	400(5)
H-6007 No. 3 CRU Reactor Preheater	150	NOx	0.065(6)	–
		CO	0.040	–
			0.060(3)	–
			0.080(4)	–
			–	400(5)
H-6014 No. 2 CTU Preflash Tower Reboiler	72(7)	NOx	0.050	–
		CO	0.040	–
			0.060(3)	–
			0.080(4)	–
H-6015 No. 2 CTU Vacuum Tower Furnace	79	NOx	0.060	–
		CO	0.040	–
			0.060(3)	–
			0.080(4)	–

Notes:
1. 365-day rolling average, including startup, shutdown, and malfunction emissions, except as otherwise specified in the specific conditions. Time period basis is midnight to midnight.
2. Reserved.
3. 24-hour rolling average limit calculated hourly on the hour. Limit does not apply during low fired duty and catalyst regeneration. Low fired duty is defined as less than 30% of the maximum fired rate. CO

emissions during startup, shutdown, or malfunction will not be used for determining compliance with the 24-hour rolling average limit provided that the facility implements good air pollution control practices to minimize emissions during such periods.

4. 7-day rolling average limit during low fired duty only. Time period basis is midnight to midnight. Limit does not apply during catalyst regeneration. Low fired duty is defined as less than 30% of the maximum fired rate and applies to heaters H-0001, H-0048, H-6007, H-6014, and H-6015. CO emissions during startup, shutdown, or malfunction will not be used for determining compliance with the 24-hour rolling average limit provided that the facility implements good air pollution control practices to minimize emissions during such periods.
5. 7-day rolling average limit during catalyst regenerations only. Time period basis is midnight to midnight. Limit does not apply during low fired duty, defined as less than 30% of the maximum fired rate. Catalyst regeneration applies to H-0048 and H-6007 only. CO emissions during startup, shutdown, or malfunction will not be used for determining compliance with the 24-hour rolling average limit provided that the facility implements good air pollution control practices to minimize emissions during such periods.
6. Supersedes H-6007 NOx emission limit included in specific condition EUG HTR-2 of permit No. 98-104-TV.
7. Supersedes H-6014 fired duty limit included in specific condition EUG HTR-2 of permit No. 98-104-TV.

i. Within 180 days of commencement of operation of Ultra Low NOx burners installed in H-0001, H-0048, H-6007, and H-6015, the permittee shall certify, calibrate, maintain and operate NOx and CO Continuous Emission Monitoring Systems (CEMS) in accordance with the requirements of 40 CFR 60.11, 60.13, and Part 60 Appendix A, B, and F. With respect to 40 CFR 60, Appendix F, in lieu of the requirements of 40 CFR Appendix F sections 5.1.1, 5.1.3, and 5.1.4, the permittee shall conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) once every twelve calendar quarters, provided that a cylinder gas audit is conducted each calendar quarter.

[Consent Decree Resolving Civil Action H-01-4430]

ii. The limits, standards and conditions included in specific condition 1.A shall not be superseded by the facility Title V permit (98-104-TV).

[Consent Decree Resolving Civil Action H-01-4430]

B. Fluidized Catalytic Cracking Units (FCCUs)

Emission Unit	Pollutant	Emissions ppmvd @ 0% O2[(1)]
No. 4 FCCU	NOx	40
		60[(2)]
	SO_2	25
		50[(2)]
	CO	150
		500[(3)]
No. 5 FCCU	NOx	37.1[(4)]
		76.9 [(5)]
	SO_2	25
		50[(2)]
	CO	150
		500[(3)]

Notes:

1. 365-day rolling average, including startup, shutdown, and malfunction emissions, except as otherwise specified in the specific conditions. Time period basis is midnight to midnight.
2. 7-day rolling average. Limit applies at all times the unit is operating, except during periods of startup, shutdown, or malfunction. Time period basis is midnight to midnight.
3. 1-hour average. Time period basis is a clock hour.
4. 365-day rolling average. Limit applies at all time the No. 5 FCCU and/or waste heat boiler B-5004 are operating. Time period basis is midnight to midnight.
5. 7-day rolling average. Limit applies at all times the No. 5 FCCU and/or waste heat boiler B-5004 are operating, except during periods of startup, shutdown, or malfunction. Time period basis is midnight to midnight.

i. The permittee shall install and maintain continuous emission monitoring systems (CEMS) for measuring NOx, CO, and SO_2. The permittee shall certify, calibrate, maintain, and operate the NOx, CO, and SO_2 CEMS in accordance with the requirements of 40 CFR 60.11, 60.13, and Part 60 Appendix A, B, and F. With respect to 40 CFR 60 Appendix F, in lieu of the requirements of 40 CFR Appendix F sections 5.1.1, 5.1.3, and 5.1.4, the permittee shall conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) once every twelve calendar quarters, provided that a cylinder gas audit is conducted each calendar quarter.

[Consent Decree Resolving Civil Action H-01-4430]

ii. The No. 4 FCCU and No. 5 FCCU/B-5004 are subject to the PM, opacity, CO and SO2 standards of 40 CFR Part 60 Subpart J. The permittee shall comply with all applicable requirements for PM, opacity, CO and SO_2 including, but not limited to, the following:

[Consent Decree Resolving Civil Action H-01-4430 for 40 CFR Part 60 Subpart J]

a. §60.102 Standard for particulate matter. The No. 4 FCCU and the No. 5 FCCU shall comply with a PM emission limit of 1.0 lbs per 1000 lb coke burn. Compliance will be demonstrated by stack testing using method 5B. Compliance with the No. 4 FCCU opacity requirements shall be in accordance with "Request for Approval – Update - Alternative Monitoring Plan for FCCU Opacity Subject to 40 CFR 60 Subpart J" dated May 5, 2009 in lieu of the requirements of 40 CFR 60.102(a)(2) and 40 CFR 60.105(a)(1). Compliance with the No. 5 FCCU opacity requirements shall be in accordance with "Request for Approval – Update - Alternative Monitoring Plan for FCCU Opacity Subject to 40 CFR 60 Subpart J" dated April 18, 2007 in lieu of the requirements of 40 CFR 60.102(a)(2) and 40 CFR 60.105(a)(1).
b. §60.103 Standards for carbon monoxide
c. §60.104 Standards for sulfur dioxide
d. §60.105 Monitoring of emissions and operations. Compliance with the No. 5 FCCU coke burn-off calculation requirements shall be in accordance with "Request for Approval – Alternative Coke Burn-off Rate Equations for the No. 5 Fluidized Catalytic Cracking Unit" dated February 11, 2005.
e. §60.106 Test methods and procedures. Compliance with No. 4 FCCU and No. 5 FCCU/B-5004 PM emission limits shall be demonstrated by a stack test in accordance with paragraph 47 of the Consent Decree resolving Civil Action No. H-01-4430(B). For the No. 4 FCCU, the first stack test shall be conducted by no later

than March 31, 2009 and subsequent annual stack tests shall be conducted by December 31st of the associated year. For the No. 5 FCCU, the first stack test shall be conducted by no later than March 31, 2007 and subsequent annual stack tests shall be conducted by December 31st of the associated year. The permittee may request that stack tests be conducted less frequently following at least three (3) annual tests that demonstrate the PM limit is not being exceeded.

f. §60.107 Reporting and recordkeeping requirements. Compliance with the No. 5 FCCU coke burn-off calculation requirements shall be in accordance with "Request for Approval – Alternative Coke Burn-off Rate Equations for the No. 5 Fluidized Catalytic Cracking Unit" dated February 11, 2005.

g. §60.107 Performance test and compliance provisions

iii. The limits, standards and conditions included in specific condition 1.B shall not be superseded by the facility Title V permit (98-104-TV).

[Consent Decree Resolving Civil Action H-01-4430]

C. 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	Estimated Number of Components
No. 1 CTU Diesel Recovery Improvements	
Heavy liquid valves	2
Flanges	6
No. 6 HDT Unstabilized Naphtha Jumper to No. 9 HDT	
Light liquid valves	4
Flanges	14
HF Alky Turnaround Projects	
Light liquid valves	30
Flanges	108

i. NESHAP 40 CFR Part 63, Subpart CC applies to the following affected equipment: each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other 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

ii. Equipment determined to not be in HAP service (<5% by weight HAP) is subject to NSPS 40 CFR Part 60, Subpart GGGa, and shall comply with all applicable requirements, including but not limited to: [40 CFR 60.590a – 593a]

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

D. Flares

i. The Ponca City Refinery Coker/Combo Alky, Clean Fuels/West Plant, East Plant, South Plant and Temporary flares are subject to 40 CFR Part 60 Subpart J. The permittee shall comply with all applicable requirements including, but not limited to, the following: [40 CFR Part 60 Subpart J]

a. The flares shall not combust any fuel gas with a hydrogen sulfide (H_2S) content in excess of 0.1 gr/dscf (160 ppmv @ 60°F). [40 CFR 60.104]
b. A continuous monitoring system shall be operated and maintained to record the H2S content of all refinery fuel gas combusted in the flare. [40 CFR 60.105]

ii. As an alternative to i.a and i.b above, the Ponca City Refinery East Plant Flare may comply with 40 CFR 60.11(d) by doing all of the following: [Consent Decree Resolving Civil Action H-01-4430]

a. Installation and operation of an H_2S Continuous Emissions Monitor (CEMS) and flow monitor to continuously monitor flare flow, H_2S concentration, and continuous calculation of the corresponding SO_2 emissions.
b. Maintaining the calculated SO_2 emissions to no greater than 500 lbs of SO_2 per 24-hour period.
c. Implementing maintenance procedures to perform acoustic meter monitoring of the leakage rate for each device routed to Flare-EP. The monitoring will be performed quarterly with provisions for reduction in frequency with demonstrated performance.
d. The permittee shall certify, calibrate, maintain, and operate the H_2S Continuous Emission Monitoring System (CEMS) in accordance with the requirements of 40 CFR 60.11, 60.13, and Part 60 Appendix A, B, and F. With respect to 40 CFR 60 Appendix F, in lieu of the requirements of 40 CFR Appendix F sections 5.1.1, 5.1.3, and 5.1.4, the permittee shall conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) once every twelve calendar quarters, provided that a cylinder gas audit is conducted each calendar quarter.
e. The permittee shall be allowed to use an alternate span and relative accuracy test method to demonstrate compliance with 40 CFR 60.105(a)(4)(i) and 60.105(a)(4)(iii) in accordance with the "Request for Approval – Alternate Span and Relative Accuracy Testing Plan for East Plant Flare H2S CEMS" dated September 26, 2006.

f. The permittee shall follow the procedures outlined in paragraphs 183 through 188 of Consent Decree resolving Civil Action H-01-4430 when SO_2 emissions exceed 500 lbs per 24 hour period.

iii. As an alternative to i.a and i.b above, the Ponca City Refinery South Plant and Clean Fuels/West Plant flares may comply with 40 CFR 60.11(d) by installing a flare gas recovery system. [Consent Decree Resolving Civil Action H-01-4430]

a. Periodic maintenance may be required for properly designed and operated flare gas recovery systems. To the extent that the facility operates flare gas recovery systems, the facility will take all reasonable measures to minimize emissions while such periodic maintenance is being performed.
b. Under certain conditions, a flare gas recovery system may need to be bypassed in the event of an emergency or in order to ensure safe operation of refinery processes. The facility is allowed to temporarily bypass a flare gas recovery system under such circumstances.
c. The permittee shall follow the procedures outlined in paragraphs 183 through 188 of Consent Decree resolving Civil Action H-01-4430 when SO_2 emissions exceed 500 lbs per 24 hour period.

iv. As an alternative to i.a and i.b above, waste gases from the coker units routed to the Ponca City Refinery Coker/Combo Alky flare may comply with 40 CFR 60.11(d) by installing a flare gas recovery system.

[Consent Decree Resolving Civil Action H-01-4430]

a. Periodic maintenance may be required for properly designed and operated flare gas recovery systems. To the extent that the facility operates flare gas recovery systems, the facility will take all reasonable measures to minimize emissions while such periodic maintenance is being performed.
b. Under certain conditions, a flare gas recovery system may need to be bypassed in the event of an emergency or in order to ensure safe operation of refinery processes. The facility is allowed to temporarily bypass a flare gas recovery system under such circumstances.
c. The flare gas recovery system is not designed or required to capture all of the waste gases from coker drum processing. The facility's work practices and procedures, including operator training, are designed to maximize waste gas recovery during coker drum processing.
d. Any one of the following will be used to demonstrate that the flare gas recovery system is operating properly: Operating procedures, operator training records, maintenance records, or operating data that indicate the flare gas recovery system is functioning as designed.
e. The permittee shall implement maintenance procedures to perform acoustic meter monitoring of the leakage rate for each device routed to the Flare-CC downstream of the flare gas recovery system. The monitoring will be performed annually.

f. The permittee shall follow the procedures outlined in paragraphs 183 through 188 of Consent Decree resolving Civil Action H-01-4430 when SO_2 emissions exceed 500 lbs per 24 hour period.

v. As an alternative to i.a and i.b above, waste gas streams vented to flare downstream of the Ponca City Refinery Coker/Combo Alky flare gas recovery system may comply with 40 CFR 60.11(d) by following EPA-approved alternate monitoring plans.
[EPA-Approved Coker/Combo Alky Flare AMP Dated 12/1/04 and Revised 1/11/06]

vi. The Ponca City Refinery Temporary flare shall comply with NSPS Part 60 Subpart J by using any of the above options. [OAC 252:100-8-6(a)]

vii. The limits, standards and conditions included in specific condition 1.D shall not be superseded by the facility Title V permit (98-104-TV).
[Consent Decree Resolving Civil Action H-01-4430]

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]

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

4. The permittee shall keep records of compliance as specified in S.C. #1. These records shall be made available to regulatory personnel upon request. Required records shall be retained on location for a period of at least five (5) years following dates of recording. [OAC 252:100-43]

5. The permittee shall monitor NO_X and SO_2 emissions and maintain records as required by OAC 252:100-8-36.2(c). [OAC 252:100-8-36.2(c)]

6. 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)]

i. OAC 252:100-7 Permits for Minor Facilities

ii. OAC 252:100-11 Alternative Emissions Reduction

iii. OAC 252:100-15 Mobile Sources

iv. OAC 252:100-39 Nonattainment Areas

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

SECTION I. DUTY TO COMPLY

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

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

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

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

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

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

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

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

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

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

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

B. Records of required monitoring shall include:

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

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

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

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

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

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

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

G. Any owner or operator subject to the provisions of New Source Performance Standards

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

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

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

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

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

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

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

SECTION IV. COMPLIANCE CERTIFICATIONS

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

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

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.
[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

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

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

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

SECTION VI. PERMIT SHIELD

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

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

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

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

SECTION VIII. TERM OF PERMIT

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

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

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

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

SECTION IX. SEVERABILITY

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

SECTION X. PROPERTY RIGHTS

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

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

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking,

reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.
[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.
[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.
[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.
[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

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

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

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

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

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

SECTION XIII. INSPECTION & ENTRY

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

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

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

SECTION XIV. EMERGENCIES

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

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

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

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

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

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;

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

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

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

SECTION XV. RISK MANAGEMENT PLAN

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

SECTION XVI. INSIGNIFICANT ACTIVITIES

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

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

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

SECTION XVII. TRIVIAL ACTIVITIES

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

SECTION XVIII. OPERATIONAL FLEXIBILITY

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

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

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

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

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

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

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

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of

adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

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

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

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

SECTION XX. STRATOSPHERIC OZONE PROTECTION

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

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

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

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

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be

certified by an approved technician certification program pursuant to § 82.161;

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

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

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

SECTION XXI. TITLE V APPROVAL LANGUAGE

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

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

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

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

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

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

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

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

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

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail

to demonstrate that the source is operating in substantial compliance with all permit requirements.

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

SECTION XXII. CREDIBLE EVIDENCE

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

[OAC 252:100-43-6]

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

Re: Permit Number **98-104-C (M-6)**
Refinery 2010-2011 Turnaround Projects

Dear Mr. Gamble:

Air Quality Division has completed the initial review of your permit application referenced above. This application has been determined to be a **Tier II**. In accordance with 27A O.S. § 2-14-302 and OAC 252:002-4-7-13(c) the enclosed draft permit is now ready for public review. The requirements for public review include the following steps, which you must accomplish:

1. Publish at least one legal notice (one day) in at least one newspaper of general circulation within the county where the facility is located. (Instructions enclosed)

2. Provide for public review (for a period of 30 days following the date of the newspaper announcement) a copy of this draft permit and a copy of the application at a convenient public location within the county of the facility such as the public library in the county seat.

3. Send to AQD a copy of the proof of publication notice from Item #1 above together with any additional comments or requested changes that you may have on the draft permit.

Per your request, concurrent public and EPA review for this permit modification has been approved. A copy of the draft permit was sent to EPA Region VI for a 45-day review period. If no public comments are received on the draft permit, the draft permit will be deemed the “proposed” permit.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4200.

Sincerely,

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

KDHE, BAR
Forbes Field, Building 283
Topeka, KS 66620

SUBJECT: Permit No. 98-104-C (M-6)
Facility: Ponca City Refinery
Location: Ponca City, Oklahoma
Permit Writer: John Howell, P.E.

Dear Sir / Madame:

The subject facility has requested a Tier II construction permit. Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the **Oklahoma - Kansas** border, a copy of the draft permit will be provided to you upon request. The draft permit is also available for review on the Air Quality section of the DEQ web page at *http://www.deq.state.ok.us*.

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

Sincerely,

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

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. 98-104-C (M-6)

ConocoPhillips Company,

having complied with the requirements of the law, is hereby granted permission to construct the specified equipment for the Refinery 2010-2011 Turnaround Projects at the Ponca City Refinery located in Ponca City, Kay County, Oklahoma, subject to Standard Conditions dated July 7, 2009, 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 | **Date**