

**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY  
AIR QUALITY DIVISION**

**MEMORANDUM**

**July 1, 2002**

**TO:** Dawson Lasseter, P.E., Chief Engineer

**THROUGH:** David Schutz, P.E., New Source Permits Unit  
Eric Milligan, P.E., New Source Permits Unit

**THROUGH:** Peer Review

**FROM:** Phillip Fielder, P.E., New Source Permits Unit

**SUBJECT:** Evaluation of Permit Application **No. 2001-194-C (PSD)**  
Conoco Inc., Ponca City Refinery (SIC 2911)  
Low Sulfur Gasoline Project  
Ponca City, Kay County, Oklahoma

**SECTION I. INTRODUCTION**

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

The refinery is a Title V major source and is located in an area designated as attainment for all criteria air pollutants. The refinery submitted an initial Part 70 Permit application (Permit Number 98-104-TV) on March 17, 1998. The primary Standard Industrial Classification (SIC) code for the refinery is 2911 (Petroleum Refining). The refinery is an existing major source for the federal Prevention of Significant Deterioration (PSD) program and a Maximum Achievable Control Technology (MACT) source category regulated under 40 CFR Part 63, Subpart CC and Subpart UUU.

On February 10, 2000, the U.S. Environmental Protection Agency (U.S. EPA) published new emission standards (Tier 2 standards) for all new passenger vehicles. As part of the Tier 2 program, most large refiners are required to reduce the sulfur content of the fuel they produce. The lower fuel sulfur standards were designed to reducing fouling in catalytic converters which allows car manufacturers to optimize design of catalytic converters. As the cleaner cars enter the national fleet, the new tailpipe standards will significantly reduce emissions of nitrogen oxides from vehicles. The U.S. EPA estimates that, when fully implemented, the Tier 2 standard will reduce nitrogen oxide (NO<sub>x</sub>) emissions by nearly 3 million tons annually.

To comply with the Tier 2 standards, Conoco proposes to construct several new units at the Refinery. The new units include the following: a selective hydrogenation/naphtha splitter, a selective hydrodesulfurization unit, a naphtha isomerization unit, a hydrogen plant, a flare, and storage tanks. To address the steam demand from the Low Sulfur Gasoline Project, the refinery steam generation capacity, and the cogeneration unit reliability issues, Conoco is also proposing to install a new boiler which will be fired by refinery fuel gas.

## SECTION II. PROJECT DESCRIPTION

As previously stated, Conoco proposes to construct several new process units at the Ponca City Refinery to comply with the final U.S. EPA Tier 2 gasoline regulations. Since the new regulations affect passenger vehicle fuel only, the new units will only treat gasoline streams.

Installation and operation of the new units will not require modifying any of the existing process units in the refinery. In addition, this change will not result in debottlenecking or increased demand on any existing unit. The Low Sulfur Gasoline Project is a “back end” desulfurization and isomerization project designed to reduce FCCU naphtha sulfur concentrations to a level that complies with the Tier 2 requirements for the total refinery gasoline pool. An isomerization unit is also included in the project to recover octane lost in the desulfurization process. This project does not involve expansion of units upstream or downstream of the proposed Low Sulfur Gasoline Units. This project basically consists of treating the gasoline streams, referred to as Fluidized Catalytic Cracking (FCC) gasoline (i.e. naphtha), after it has been produced through the existing normal operations. However, associated emissions will result, therefore, a description of these sources is included here.

The process Conoco has proposed is described following, including the proposed equipment associated with each process.

### Selective Hydrogenation/Naphtha Splitter

After leaving the FCCUs, the FCC gasoline streams will be directed to a selective hydrogenation/naphtha splitter. The reactor feed will be preheated (EU ID H-8601) against the splitter bottoms. The reactor will then remove diolefins from the light catalytic naphtha (LCN) and heavy catalytic naphtha (HCN) streams and will convert light mercaptans and light sulfides to heavier sulfur compounds, which will then be recovered in the splitter bottoms (HCN) stream. The reactor will also isomerize external olefins to internal olefins. The naphtha splitter will then separate the olefin rich LCN from the sulfur rich HCN stream. The splitter bottoms, HCN, will be cooled and sent to a selective hydrodesulfurization unit. LCN will be cooled and routed to storage for eventual blending into salable product.

### Selective Hydrodesulfurization Unit

The sulfur-rich splitter bottoms will be pumped to the reactor circuit and mixed with the recycle and make-up hydrogen streams. The hydrocarbon/hydrogen mixture will be preheated (EU ID H-8602) against the reactor effluent before feeding into the first catalyst bed. The reactor effluent will be cooled against the reactor feed, then further cooled in an air-cooler and trim cooler prior to feeding into the separator. The vapor stream from the separator will be sent to an amine scrubber for hydrogen sulfide (H<sub>2</sub>S) removal and recycled to the reaction section, while the separator liquid will be sent to the stripper. H<sub>2</sub>S removal from the liquid product will be conducted in the stripper column. The stripper bottoms will be heated using a reboiler (EU ID H-8603) and will result in a sour vapor product and a sweet desulfurized HCN stream. The desulfurized HCN stream will then be pumped and cooled prior to being mixed with the LCN stream and routed to storage.

### Naphtha Isomerization Unit

During the process of treating the FCC gasoline for sulfur removal, the octane properties are impaired. As a result, Conoco will install a naphtha isomerization unit to recover the octane properties of naphtha from the No. 7 Hydrotreater. The No. 7 Hydrotreater naphtha feed is from the No. 1, 2 and 4 Crude Topping Units.

The naphtha isomerization unit will be specifically designed for the catalytic isomerization of pentane, hexane, and mixtures thereof. The reactions will take place over a catalyst bed and at operating conditions that promote isomerization and minimize hydrocracking. This isomerization catalyst will convert the normal paraffins in the feed to the high octane-number branched paraffins.

### Hydrogen Plant

As part of this project, a new hydrogen plant will be built at the Refinery to supply makeup H<sub>2</sub> to existing refinery hydrotreaters (No. 4, No. 5, and No. 6) and the new low sulfur gasoline selective hydrodesulfurization unit. The hydrogen plant will receive only pipeline quality natural gas as feed/fuel. The natural gas will flow to two parallel guard desulfurizers and from the desulfurizers to the hydrogen plant reformer heater (EU ID H-8801) and then to a shift converter. From the shift converter, the stream will flow through a heat exchanger to a hot condensate separator. Flow out of the separator will continue to a water cooler and then a series of six parallel, pressure swing adsorbers (PSAs). From the PSAs, the hydrogen will be sent to the refinery hydrogen system. The PSA offgas, consisting primarily of CO<sub>2</sub> and smaller amounts of CO, hydrogen, and methane will be circulated back to H-8801 to be combusted.

### Gas-Fired Boiler

A refinery fuel gas-fired, mechanical draft boiler will be installed to support the Low Sulfur Gasoline Project. The heat rating of the proposed boiler is 483.2 million British thermal units per hour (MMBtu/hr). This boiler will provide the additional high pressure steam required by the Low Sulfur Gasoline Project, as well as provide enhanced reliability for the existing on-site cogeneration units.

### Storage Tanks

Six new storage tanks are proposed as part of the Low Sulfur Gasoline Project. Four of the six tanks will have a capacity of 80,000 barrels (bbl) each and will contain finished gasoline. The remaining two tanks will have a capacity of 200,000 bbl each and will contain sour fluidized catalytic cracker (FCC) gasoline.

### Flare

A flare (EU ID FLARE CF) is proposed for construction as part of this permit application. The new Low Sulfur Gasoline flare will serve the units from this project. As a part of separate projects, other refinery units may be connected to this new flare in the future.

### Cooling Tower

One cooling tower (EU ID CT-11) is proposed for construction as part of this permit application. Emissions for PM<sub>10</sub> are calculated using design parameters for an existing cooling tower at the site (EU ID CT-10), which is located in proximity to the proposed cooling tower. The recirculating flow rate of the proposed cooling tower is 10,000 gallons per minute (gpm).

### Associated Sources

As mentioned, this proposed project is a “back-end” treatment project and no modifications will occur at any existing units. The treatment system will be designed to treat the current maximum naphtha production rate and will not result in the debottlenecking of any units. However, this project will require routing of off-gas streams from the selective hydrogenation/naphtha splitter, hydrodesulfurization unit, and naphtha isomerization unit to the existing Saturated Gas Plant for separation of propane and butane compounds from methane and ethane. Methane/ethane from the Saturated Gas Plant will be routed to the refinery fuel gas system and propane/butane to sales. Additionally, the proposed equipment will result in an increase in wastewater flow which will be handled by the existing wastewater system. Therefore, this project will not result in associated emissions except for the Saturated Gas Plant and the wastewater system. However, in order to do a conservative analysis, Conoco calculated potential associated emission increases from other sources. These increases were based on the actual average unit throughput to the future potential assuming the Crude Units and FCCUs would operate at the maximum rates. The affected units are identified in the emissions section.

## **SECTION III. EMISSIONS**

The Ponca City Refinery (PCR) is an existing PSD major source. To determine if this project is subject to PSD review, emissions from the added and associated sources are reviewed. This section quantifies the emission increases from the process heaters, gas-fired boiler, flare, equipment leaks, storage tanks, cooling tower, wastewater operations, and emissions associated with increased steam production in order to determine PSD applicability. Associated emissions

are based on the actual to future potential method. Emission factor bases for the proposed sources are discussed in the BACT analysis.

Process Heaters

A total of four process heaters (EU IDs H-8601, H-8602, H-8603, and H-8801) are proposed for construction as part of this permit application. Emissions for all criteria pollutants from the process heaters are calculated using AP-42 (7/98), Tables 1.4-1 and 1.4-2 emission factors for natural gas combustion, with the exception of NO<sub>x</sub> and SO<sub>2</sub>. The NO<sub>x</sub> emission factors are based on vendor guarantees for ultra low NO<sub>x</sub> burners (ULNB). Emission factors for SO<sub>2</sub> are based on NSPS Subpart J-allowable H<sub>2</sub>S content of 0.10 grains per dry standard cubic foot (grains/dscf) (160 parts per million on a volumetric basis [ppm<sub>v</sub>]) and 660 btu/scf for refinery fuel gas for three of the four process heaters (EU IDs H-8601, H-8602, and H-8603). Since the hydrogen plant reformer heater (EU ID H-8801) will burn only pipeline quality natural gas, the SO<sub>2</sub> emissions are based on the AP-42 (7/98), Table 1.4-2 emission factor for pipeline quality natural gas.

Emission Unit	Maximum Firing Rate, MMBTU/HR	Pollutant	Emission Factors, lb/MMBTU	Emissions	
				lb/hr	TPY
H-8601, Splitter Reboiler	149	NO <sub>x</sub>	0.035	5.22	22.84
		SO <sub>2</sub>	0.0407	6.06	26.56
		CO	0.0824	12.28	53.78
		VOC	0.0054	0.80	3.52
		PM <sub>10</sub>	0.0075	1.12	4.89
H-8602, Hydrodesulfurization Heater	44	NO <sub>x</sub>	0.035	1.54	6.75
		SO <sub>2</sub>	0.0407	1.79	7.84
		CO	0.0824	3.63	15.88
		VOC	0.0054	0.24	1.04
		PM <sub>10</sub>	0.0075	0.33	1.45
H-8603, Stabilizer Reboiler	33	NO <sub>x</sub>	0.035	1.16	5.06
		SO <sub>2</sub>	0.0407	1.34	5.88
		CO	0.0824	2.72	11.91
		VOC	0.0054	0.18	0.78
		PM <sub>10</sub>	0.0075	0.25	1.08
H-8801, Hydrogen Plant Reformer	90	NO <sub>x</sub>	0.035	3.15	13.80
		SO <sub>2</sub>	0.0006	0.05	0.24
		CO	0.0824	7.42	32.48
		VOC	0.0054	0.49	2.13
		PM <sub>10</sub>	0.0075	0.68	2.96

Boiler

One gas-fired, mechanical draft boiler (EU ID B-0008) is proposed for construction as part of this permit application. The boiler will combust only NSPS Subpart J-compliant refinery fuel gas. Emissions for criteria pollutants from the proposed boiler are calculated using AP-42 (7/98), Tables 1.4-1 and 1.4-2 natural gas combustion emission factors, with the exception of NO<sub>x</sub> and SO<sub>2</sub>. The NO<sub>x</sub> emission factor is based on vendor guarantees for ULNB. The emission factor for SO<sub>2</sub> is based on the NSPS Subpart J-allowable H<sub>2</sub>S content of 0.10 grains/dscf (160 ppm<sub>v</sub>) and 660 btu/scf of refinery fuel gas for the proposed boiler.

Emission Unit	Maximum Firing Rate, MMBTU/HR	Pollutant	Emission Factors, lb/MMBTU	Emissions	
				lb/hr	TPY
B-0008, Boiler	483.2	NO <sub>x</sub>	0.035	16.91	74.07
		SO <sub>2</sub>	0.0407	19.67	86.14
		CO	0.0824	39.82	174.39
		VOC	0.0054	2.61	11.43
		PM <sub>10</sub>	0.0075	3.62	15.87

Tanks

Emissions are calculated based on the anticipated throughput for these tanks using U.S. EPA’s TANKS 4.09 program. Emissions are conservatively estimated by assuming each tank contains a hypothetical hydrocarbon, which maintains a constant vapor pressure of 11 pounds per square inch absolute (psia), regardless of temperature.

Two of the tanks will contain sour FCC gasoline. The remaining four new tanks will provide storage where finished gasoline can be tested to verify that it meets the Tier 2 standards.

Parameter	Tank Numbers	
	T-145, T-146, T-157, and T-161	T-121 and T-122
Contents	Hydrocarbons	Hydrocarbons
Capacity, barrels	80,000	200,000
Height, feet	40	40
Diameter, feet	134	220
Vapor Pressure, psia	11.0	11.0
Annual Throughput, gallons	5,241,600	8,400,000
Design	Internal Floating Roof	Internal Floating Roof

Tanks	VOC Emissions	
	lb/hr	TPY
T-145	3.71	16.24
T-146	3.71	16.24
T-157	3.71	16.24
T-161	3.71	16.24
T-121	6.56	28.75
T-122	6.56	28.75
<b>Totals</b>	<b>27.96</b>	<b>122.46</b>

Equipment Leaks

The project will result in an increase in VOC emissions from equipment leaks (part of EU ID FUG) due to the installation of equipment such as flanges, valves, compressors, drains, and pumps. Fugitive emitting equipment will be associated with the selective hydrogenation unit, the selective hydrodesulfurization unit, the naphtha isomerization unit, and the hydrogen plant. The emissions increases for equipment leaks are calculated using design-basis fugitive counts in concert with emission factors (EF) that were developed specifically for the Ponca City Refinery and Compliance Guidelines – NSPS Subpart QQQ, Table 2.

Fugitive Components, FUG	Number	Emission Factor, lb/hr/source	VOC Emissions	
			lb/hr	TPY
<b>SHU, Splitter, HDS</b>				
Gas Valves	0	0.00253	0.00	0.00
Light Liquid Valves	1108	0.00468	5.19	22.71
Heavy Liquid Valves	0	0.00051	0.00	0.00
Flanges	2875	0.00013	0.37	1.64
Light Liquid Pumps	10	0.04509	0.45	1.97
Heavy Liquid Pumps	0	0.04718	0.00	0.00
Gas Compressors	1	0.50265	0.50	2.20
Gas Relief Valves to Atmosphere	0	0.22928	0.00	0.00
Gas Relief Valves to Flare	15	0.00459	0.07	0.30
Sample Stations	5	0.03307	0.17	0.72
Drains	50	0.03500	1.75	7.67
Controlled Junction Boxes	10	0.07000	0.70	3.07
<b>Subtotals</b>			<b>9.20</b>	<b>40.28</b>

Fugitive Components, FUG	Number	Emission Factor, lb/hr/source	VOC Emissions	
			lb/hr	TPY
<b>Isomerization Unit</b>				
Gas Valves	0	0.00253	0.00	0.00
Light Liquid Valves	440	0.00468	2.06	9.02
Heavy Liquid Valves	0	0.00051	0.00	0.00
Flanges	1099	0.00013	0.14	0.63
Light Liquid Pumps	8	0.04509	0.36	1.58
Heavy Liquid Pumps	0	0.04718	0.00	0.00
Gas Compressors	2	0.50265	1.01	4.40
Gas Relief Valves to Atmosphere	0	0.22928	0.00	0.00
Gas Relief Valves to Flare	15	0.00459	0.07	0.30
Sample Stations	5	0.03307	0.17	0.72
Drains	50	0.03500	1.75	7.67
Controlled Junction Boxes	10	0.07000	0.70	3.07
Subtotals			8.00	35.04
<b>Hydrogen Plant</b>				
Gas Valves	15	0.00253	0.04	0.17
Light Liquid Valves	146	0.00468	0.68	2.99
Heavy Liquid Valves	0	0.00051	0.00	0.00
Flanges	450	0.00013	0.06	0.26
Light Liquid Pumps	2	0.04509	0.09	0.39
Heavy Liquid Pumps	0	0.04718	0.00	0.00
Gas Compressors	2	0.50265	1.01	4.40
Gas Relief Valves to Atmosphere	0	0.22928	0.00	0.00
Gas Relief Valves to Flare	15	0.00459	0.07	0.30
Sample Stations	8	0.03307	0.26	1.16
Drains	50	0.03500	1.75	7.67
Controlled Junction Boxes	20	0.07000	1.40	6.13
Subtotals			7.88	34.52
<b>TOTALS</b>			<b>20.82</b>	<b>91.14</b>



Cooling Tower

Operation of the cooling tower will result PM<sub>10</sub> and VOC emissions. Emissions are based on a recirculating flow of 10,000 gallons per minute, a total dissolved solids (TDS) concentration of 850 ppm and 99.998% control by use of drift eliminators. Emissions for VOC are calculated using the controlled emission factor for petroleum refinery cooling towers presented in AP-42 (1/95), Table 5.1-2.

EU	PM <sub>10</sub> Emissions		VOC Emissions	
	lb/hr	TPY	lb/hr	TPY
Cooling tower, CT-11	0.09	0.37	0.42	1.84

Flare

One flare (EU ID FLARE CF) is proposed for construction as part of this permit application. Because the flare will be used only for upset conditions, it is assumed that emissions from the flare will only result from the operation of the pilot, which is fueled by natural gas. The flare pilot is rated at 0.2 MMBtu/hr. Emissions for NO<sub>x</sub>, CO, and VOC are calculated using AP-42 (1/95), Section 13.5 emission factors for flare operations. Emissions for SO<sub>2</sub> are calculated using AP-42 emission factors for commercial grade natural gas combustion, as there is not an emission factor for this pollutant in AP-42, Section 13.5. The PM<sub>10</sub> emission factor was assumed to be zero, since it will be designed to be smokeless during normal operating scenarios.

Emission Unit	Maximum Firing Rate, MMBTU/HR	Pollutant	Emission Factors, lb/MMBTU	Emissions	
				lb/hr	TPY
Flare CF	0.2	NO <sub>x</sub>	0.068	0.01	0.06
		SO <sub>2</sub>	0.0006	0.0001	0.001
		CO	0.37	0.07	0.32
		VOC	0.14	0.03	0.12
		PM <sub>10</sub>	-	-	-

Associated Sources

The following is a review of associated emissions from the proposed project. Associated emissions calculations are based on the 2-year past actual to future potential methodology for each of the listed sources.

As previously indicated, the Saturated Gas Plant will receive additional gas from the new units and have associated emissions. Emissions will result due to the added demand on the Saturated Gas Plant heater (H-0010). The past actual emissions are based on the last 2-year average fired duty. Future potential emissions are based on potential emissions as limited by the existing permit (No. 91-081-O).

Emission factors come from AP-42 (7/98), Tables 1.4-1 and 1.4-2 natural gas combustion with the exception of SO<sub>2</sub>. The emission factor for past actual SO<sub>2</sub> is based on the average H<sub>2</sub>S content of 11.95 ppm<sub>v</sub> with future potential based on the permit limit of 160 ppm<sub>v</sub> H<sub>2</sub>S.

The additional fuel gas created as a result of the off-gas being processed by the Saturated Gas Plant will not have an impact on the fuel gas H<sub>2</sub>S content because of excess capacity in the amine treating units.

Emission Unit	Pollutant	2-year Average Emissions, TPY	Future Potential	Associated Emissions, TPY
H-0010	NO <sub>x</sub>	3.95	15.20	11.25
	SO <sub>2</sub>	0.12	4.97	4.95
	CO	3.32	12.78	9.45
	VOC	0.22	0.84	0.62
	PM <sub>10</sub>	0.30	1.16	0.86

Additional wastewater will also result from the proposed project. This additional wastewater will be processed by the existing wastewater treatment system. The 2-year average past actual to future potential increase in flow rate has been conservatively estimated at 5% of the total wastewater flow. The following table shows the estimated emission increase.

Emission Unit	Pollutant	2-year Average Emissions, TPY	% Increase	Associated Emissions, TPY
Wastewater Plant	VOC	31.39	5	1.57

While this project will not result in associated emissions other than those identified from H-0010 and the wastewater plant, Conoco did a conservative estimate of other associated emissions. This method was based on holding the No. 1, 2, and 4 Crude Units and the No. 4 and 5 FCCUs at their maximum potential throughput rates. The Ponca City Refinery Linear Program Model was then used to find maximum upstream unit rates. The maximum future unit rates were then compared to the 2-year past actual unit rates to determine the percentage increase in rate. This percentage increase was then used to scale up the past 2-year actual average emissions from each unit to estimate associated emissions for upstream units. Emissions are based on AP-42 (7/98), Tables 1.4-1 and 1.4-2 natural gas combustion emission factors with the exception of SO<sub>2</sub>. The emission factor for SO<sub>2</sub> is based on the average H<sub>2</sub>S content for the year 2000 of the fuel stream used by that source.

Emission Unit	Maximum Firing Rate, MMBTU/HR	Pollutant	2-year Average Emissions, TPY	% Increase	Associated Emissions, TPY
H-6007	61.02	NO <sub>x</sub>	105.72	5.57	5.89
		SO <sub>2</sub>	10.66		0.59
		CO	31.59		1.76
		VOC	2.07		0.12
		PM <sub>10</sub>	2.86		0.16

Emission Unit	Maximum Firing Rate, MMBTU/HR	Pollutant	2-year Average Emissions, TPY	% Increase	Associated Emissions, TPY
H-6012	25	NO <sub>x</sub>	9.35	5.57	0.52
		SO <sub>2</sub>	2.62		0.15
		CO	7.76		0.43
		VOC	0.51		0.03
		PM <sub>10</sub>	0.71		0.04
H-6013	32	NO <sub>x</sub>	14.95	5.57	0.83
		SO <sub>2</sub>	4.19		0.23
		CO	12.42		0.69
		VOC	0.82		0.05
		PM <sub>10</sub>	1.13		0.06
H-0047	25	NO <sub>x</sub>	5.62	10.56	0.59
		SO <sub>2</sub>	0.19		0.02
		CO	3.57		0.38
		VOC	0.33		0.03
		PM <sub>10</sub>	0.45		0.05
H-0023	16.4	NO <sub>x</sub>	10.13	16.39	1.66
		SO <sub>2</sub>	0.31		0.05
		CO	8.41		1.38
		VOC	0.55		0.09
		PM <sub>10</sub>	0.76		0.12
H-0028	220	NO <sub>x</sub>	107.31	4.61	4.95
		SO <sub>2</sub>	1.18		0.05
		CO	32.07		1.48
		VOC	2.10		0.10
		PM <sub>10</sub>	2.90		0.13
H-0029	53.2	NO <sub>x</sub>	53.36	4.61	2.46
		SO <sub>2</sub>	0.59		0.03
		CO	15.95		0.74
		VOC	1.05		0.05
		PM <sub>10</sub>	1.44		0.07
H-0011	11.7	NO <sub>x</sub>	1.82	0.10	<0.01
		SO <sub>2</sub>	0.03		<0.01
		CO	0.87		<0.01
		VOC	0.08		<0.01
		PM <sub>10</sub>	0.13		<0.01
H-0057	75.2	NO <sub>x</sub>	21.59	6.56	1.42
		SO <sub>2</sub>	0.53		0.03
		CO	17.93		1.18
		VOC	1.18		0.08
		PM <sub>10</sub>	1.63		0.11

Emission Unit	Maximum Firing Rate, MMBTU/HR	Pollutant	2-year Average Emissions, TPY	% Increase	Associated Emissions, TPY
H-0058	60.96	NO <sub>x</sub>	16.32	6.56	1.07
		SO <sub>2</sub>	0.40		0.03
		CO	13.56		0.89
		VOC	0.89		0.06
		PM <sub>10</sub>	1.23		0.08
H-0059	76.8	NO <sub>x</sub>	21.15	6.56	1.39
		SO <sub>2</sub>	0.52		0.03
		CO	17.56		1.15
		VOC	1.15		0.08
		PM <sub>10</sub>	1.59		0.10
<b>TOTALS</b>		<b>NO<sub>x</sub></b>	<b>-</b>	<b>-</b>	<b>20.78</b>
		<b>SO<sub>2</sub></b>	<b>-</b>		<b>1.21</b>
		<b>CO</b>	<b>-</b>		<b>10.08</b>
		<b>VOC</b>	<b>-</b>		<b>0.69</b>
		<b>PM<sub>10</sub></b>	<b>-</b>		<b>0.92</b>

Total Emissions

Source	NO <sub>x</sub>		CO		VOC		SO <sub>2</sub>		PM <sub>10</sub>	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
H-8601	5.22	22.84	12.28	53.78	0.80	3.52	6.06	26.56	1.12	4.89
H-8602	1.54	6.75	3.63	15.88	0.24	1.04	1.79	7.84	0.33	1.45
H-8603	1.16	5.06	2.72	11.91	0.18	0.78	1.34	5.88	0.25	1.08
H-8801	3.15	13.80	7.42	32.48	0.49	2.13	0.05	0.24	0.68	2.96
B-0008	16.91	74.07	39.82	174.39	2.61	11.43	19.67	86.14	3.62	15.87
T-145	-	-	-	-	3.71	16.24	-	-	-	-
T-146	-	-	-	-	3.71	16.24	-	-	-	-
T-157	-	-	-	-	3.71	16.24	-	-	-	-
T-161	-	-	-	-	3.71	16.24	-	-	-	-
T-121	-	-	-	-	6.56	28.75	-	-	-	-
T-122	-	-	-	-	6.56	28.75	-	-	-	-
FUG	-	-	-	-	20.82	91.14	-	-	-	-
CT-11	-	-	-	-	0.42	1.84	-	-	0.09	0.37
Flare CF	0.01	0.06	0.07	0.32	0.03	0.12	<0.01	<0.01	-	-
Associated	-	32.03	-	19.53	-	2.88	-	6.16	-	1.78
<b>TOTALS</b>	<b>27.99</b>	<b>154.61</b>	<b>65.94</b>	<b>308.29</b>	<b>53.55</b>	<b>237.34</b>	<b>28.91</b>	<b>132.82</b>	<b>6.09</b>	<b>28.40</b>

Toxic/HAP Emissions

The majority of the HAPs emissions will be subject to National Emission Standards for Hazardous Air Pollutants (NESHAPs), 40 CFR Part 63, Subpart CC and exempt from regulation under Oklahoma Administrative Code (OAC 252:100-41). However, small quantities of HAP emissions from the heaters and boiler will be emitted and are included here for OAC 252:100-41 applicability. In addition, non-HAP toxic emissions are quantified.

Heaters and boiler toxic/HAP emissions are based on AP-42 (7/98), Table 1.4-3. The only toxic to be emitted from the tanks in a significant quantity is 1,2,4-trimethylbenzene. Emissions are based on the worst-case gasoline concentration. Emissions of toxics above a de minimis level were modeled using SCREEN3 to demonstrate compliance with the Maximum Ambient Air Concentration (MAAC). Results of modeling shown below demonstrate compliance.

Pollutant	Toxicity Category	CAS Number	Emissions		De Minimis	
			lb/hr	TPY	lb/hr	TPY
1,2,4-Trimethylbenzene	C	25551137	0.80	3.49	5.60	6.0
Hexane	C	110543	1.41	6.18	5.60	6.0
Pentane	C	109660	2.04	8.92	5.60	6.0

Pollutant	Maximum Impact, ug/m <sup>3</sup>	MAAC, ug/m <sup>3</sup>
Hexane	36	17,628
Pentane	52	35,000

**SECTION IV. PROJECT SIGNIFICANCE LEVEL COMPARISON**

Since the facility is an existing major source for Prevention of Significant Deterioration (PSD), the proposed project “net emissions” are compared to the significant levels to determine if full PSD review is required. This comparison is done on a pollutant-by-pollutant basis. The listed emissions only include the added sources and associated emissions and not the 3-year contemporaneous totals or “net emissions” since there are not sufficient available reductions to allow a “net out” of any pollutant. As shown below, the proposed project will result in emissions above the significance levels for all pollutants. However, the contemporaneous emissions or “net emissions” are required to determine if the proposed modification will result in a significant impact for any pollutant. These emissions are included in the significant impact section of this memorandum.

The table below summarizes the emission increases submitted in Conoco’s January 2002 permit application. After submittal of the air dispersion modeling analysis in March 2002, the methodology for calculating associated emissions was revised to an “actuals to potentials” comparison for downstream affected units which resulted in revised project emissions (as summarized previously in Section III). The DEQ determined that the changes in associated emissions would have an insignificant impact on the air quality modeling.

Pollutant	Emissions	PSD Significance Level	PSD Review Required
NO <sub>x</sub>	143.88	40	Yes
CO	299.27	100	Yes
VOC	255.45	40	Yes
PM <sub>10</sub>	27.58	15	Yes
SO <sub>2</sub>	128.11	40	Yes

**SECTION V. SCOPE OF REVIEW**

Since the modification will result in net emissions which exceed the significance level for all pollutants, the project is subject to full PSD review for VOC including Tier II public review, best available control technology (BACT), and an ambient impacts analysis.

The proposed equipment is also subject to NSPS 40 CFR Part 60 Subparts A, Db, J, Kb, GGG, and QQQ, NESHAPs 40 CFR Part 61 Subpart FF, and NESHAPs 40 CFR Part 63, Subpart CC.

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

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

**SECTION VI. PSD REVIEW**

**Best Available Control Technology (BACT)**

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

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

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

**BACT Analysis for Process Heaters and Boiler**

NO<sub>x</sub>

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling NO<sub>x</sub> emissions from the heaters/boiler and their effective emission levels.

<b>Technology</b>
Base Case
Water/Steam Injection
Selective Non-Catalytic Reduction (SNCR)
Combustion Control (including Ultra Low-NO <sub>x</sub> )
Selective Catalytic Reduction (SCR)
Ultra Low-NO <sub>x</sub> Burners and SNCR
Ultra Low-NO <sub>x</sub> Burners and SCR

No Control – Base Case

In order to determine the feasibility of applicable control technologies, it is required to determine a base case emission rate as a comparison. Because of regulatory effects and efforts to produce environmental friendly products, burner manufacturers are constantly improving combustion technology. This improvement can occur rapidly and affects not only the most advanced technology but also the standard technology. In addition, specific application can affect the base emission rate. Therefore, a base case is a moving target that is determined on a case-by-case basis based on commercially available technology.

Recently issued permits (1999 to 2001) within the state of Oklahoma which were not required to be reviewed for applicability of Best Available Control Technology and which involved process heaters were reviewed to help identify the base case. These permits involved the installation of hot oil heaters to large process heaters. Emission rates ranged from 0.05 lb/MMBTU to 0.07 lb/MMBTU. Therefore, based on recently issued permits and consultation with a heater manufacturer, the proposed base case emission rate is 0.08 lb/MMBTU.

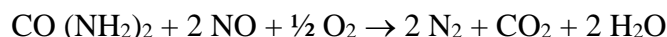
#### Water/Steam Injection

The injection of steam or water into the combustion zone can decrease peak flame temperatures, thus reducing thermal NO<sub>x</sub> formation. Therefore, it is important that the injected water/steam reach the primary flame zone. In order to reach the primary flame zone, the steam is injected either into the fuel, the combustion air, or directly into the combustion chamber. Water injection may be preferred over steam due to its availability, lower cost, and greater thermal effect.

Steam injection is predominately used with gas turbines. Few full-scale retrofit or test trials of steam injection on process heaters have been performed. Therefore, there is little data to document the effectiveness of water/steam injection, relative to the other technologies presented in this analysis. For these reasons, steam injection is considered technically infeasible and is eliminated from further evaluation as a potential NO<sub>x</sub> control for the proposed process heaters and gas-fired boiler.

#### Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR) is a post-combustion NO<sub>x</sub> control technology based on the reaction of NH<sub>3</sub> and NO<sub>x</sub>. SNCR involves injecting urea/NH<sub>3</sub> into the combustion gas path to reduce the NO<sub>x</sub> to nitrogen and water. This reaction is described by the following chemical equation:



The optimum exhaust gas temperature range for implementation of SNCR is 1,200 °F to 2,000 °F. Operation at temperatures below this range results in NH<sub>3</sub> slip, while operation above this temperature range results in oxidation of NH<sub>3</sub>, forming additional NO<sub>x</sub>. In addition, the urea/ammonia must have sufficient residence time, approximately 3 to 5 seconds, at the optimum operating temperatures for efficient NO<sub>x</sub> reduction.

The exhaust temperatures of the process heaters range from 350 °F to 700 °F, and temperatures ranging from 1,200 °F to 2,000 °F are required to prevent significant ammonia slip.

Three of the four proposed heaters at the Ponca City Refinery are natural draft heaters. SNCR can only be used in induced draft process heaters because of the need to recirculate the flue gas. In addition, there is currently only one refinery heater in the U.S. being controlled by SNCR. The



exhaust temperature of the remaining mechanical draft heater is not sufficient to prevent significant ammonia slip. Therefore, SNCR is deemed technically infeasible for the control of NO<sub>x</sub> emissions from all proposed process heaters. SNCR remains a technically feasible option for the gas-fired boiler.

### Combustion Control

Combustion controls reduce NO<sub>x</sub> emissions by controlling the combustion temperature or the availability of oxygen. These are referred to as “low NO<sub>x</sub> burners” or “ultra low NO<sub>x</sub> burner.”

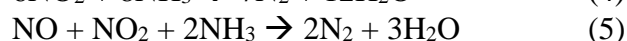
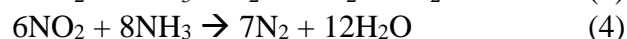
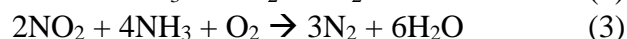
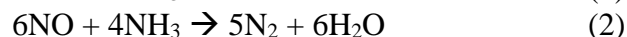
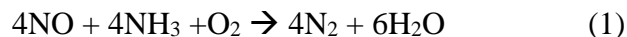
There are several designs of low/ultra low NO<sub>x</sub> burners (ULNB) currently available. These burners combine two NO<sub>x</sub> reduction steps into one burner, typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment.

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

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

### Selective Catalytic Reduction (SCR)

SCR is a process that involves post-combustion removal of NO<sub>x</sub> from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho 1994):



The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO<sub>x</sub> decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, ammonia slip emissions, and design of the NH<sub>3</sub> injection system.

Three types of catalyst bed configurations have been successfully applied to commercial sources: the moving bed reactor, the parallel flow reactor, and the fixed bed reactor. The fixed bed reactor is applicable to sources with little or no particulate present in the flue gas, such as would be the case for this application.

Reduction catalysts are divided into two groups: platinum and base metal (primarily vanadium or titanium). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/ $\text{NO}_x$  ratio, and optimum oxygen concentration. A disadvantage common to both platinum and base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but have been shown also to have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of  $\text{NH}_3$  to either nitrogen oxides (thereby actually increasing  $\text{NO}_x$  emissions) or ammonium nitrate.

Sulfur content of the fuel can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide (from trace sulfur in gas and the mercaptans used as an odorant) to sulfur trioxide ( $\text{SO}_3$ ), which combines with water to form sulfuric acid. Sulfur trioxide and sulfuric acid reacts with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled or may be emitted from the stack as increased emissions of  $\text{PM}_{10}$ . Fouling may eventually lead to increased system pressure drop over time and decreased heat transfer efficiencies.

The SCR process also is subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result either of prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a 3-year lifetime to very low emission level, high performance catalyst systems.

SCR manufacturers typically estimate 10 to 20 ppm of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high  $\text{NO}_x$  reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which necessarily results in ammonia slip. Thus, an emissions trade-off between  $\text{NO}_x$  and ammonia occurs in high  $\text{NO}_x$  reduction applications.

SNCR and Combustion Controls/SCR and Combustion Controls

These methods use a combination of control methods to reduce emissions.

2. Eliminate Technically Infeasible Options

All the control methods identified are considered technically feasible except for water/steam injection for controlling the heaters/boiler. Steam injection is predominately used with gas turbines. There is little data available to document the effectiveness of water/steam injection for heaters and no application of this type could be found. Steam injection has been specified as a control method for boilers on a very limited basis (only one listed on the RACT/BACT/LAER database). However, review of this determination indicated a controlled emission rate higher than low NO<sub>x</sub> burners produced today. Additionally, no recent determinations have specified steam injection and there are operating issues concerning flame stability using low NO<sub>x</sub> burners with steam injection, therefore, it is considered infeasible for this review.

3. Rank Remaining Options

<b>Technology</b>	<b>Typical Control Range (% Removal)</b>	<b>Typical Emission Level</b>
ULNB/SCR	89	0.0085
ULNB/SNCR	81	0.015
SCR	73	0.022
ULNB	56	0.035
LNB	Base Case	0.08
SNCR	-	0.087

4. Evaluate Remaining Options

The remaining technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated.

UNLB/SCR

The potential environmental impacts associated with the use of SCR in combination with ULNB are summarized below:

- Unreacted ammonia would be emitted to the atmosphere (ammonia slip); ammonia is a PM<sub>10</sub> (and PM<sub>2.5</sub>) precursor;
- Small amounts of ammonium would also combine with NO<sub>x</sub> and SO<sub>2</sub> to form ammonia salts, which would be emitted to the atmosphere as PM<sub>10</sub>;

- There are safety issues associated with the transportation, handling, and storage of aqueous ammonia. The storage of aqueous ammonia (which is substantially lower risk than for anhydrous ammonia) is regulated under Occupational Safety and Health Act (OSHA) regulations and the Risk Management Planning (RMP) provisions of Clean Air Act Amendments Title III, Section 112(r); and
- The use of SCR technology would result in ammonia emissions as a result of unreacted ammonia leaving the SCR unit. It is important to note, that ammonia slip levels vary over the life of the catalyst. With a fresh catalyst, slip levels of only a few ppm may be sufficient to maintain the permitted NO<sub>x</sub> emission rate. As catalyst ages, more ammonia (slip) is required until the catalyst must be replaced.

In summary, the transport, handling, and storage of aqueous ammonia presents limited environmental risks due to potential spills and subsequent evaporation of ammonia gas to the atmosphere. Potential environmental impacts from the storage and handling of aqueous ammonia are not considered unreasonable.

Because ULNB/SCR is considered to be a technically feasible add-on control option and not eliminated due to environmental impacts, its cost effectiveness was calculated. The cost effectiveness was evaluated for the proposed process heaters and boiler based on the “EPA Air Pollution Control Cost Manual,” Sixth Edition and vendor cost estimates.

Source	Uncontrolled Emissions (TPY)	Emissions Reduction (TPY)	Annualized Cost (\$/year)	Cost Effectiveness (\$/ton)
H-8601	52	46.28	389,362	8,413
H-8602	15	13.35	204,762	15,338
H-8603	12	10.68	226,192	21,179
H-8801	32	28.48	314,761	11,052
B-0008	169	150.41	747,839	4,972

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

UNLB/SNCR

While this control option has the same potential environmental impacts associated with the use of ammonia, it is also considered to be a technically feasible add-on control option and not eliminated due to environmental impacts. However, there is some question about the SNCR being able to achieve the control levels listed since available data did not list any heaters or boilers with this control option.

A cost analysis was not conducted for this option since it achieves less control than SCR and, as stated in the “Petroleum Refinery Tier 2 BACT Analysis,” January 2001, “SNCR with combustion control is economically inferior to SCR with combustion control.”

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

SCR

This control option is also considered to be a technically feasible add-on control option which was not eliminated due to environmental impacts associated with the use of ammonia and catalyst.

The cost effectiveness was evaluated for the proposed process heaters and boiler based on the “EPA Air Pollution Control Cost Manual,” Sixth Edition and vendor cost estimates.

<b>Source</b>	<b>Uncontrolled Emissions (TPY)</b>	<b>Emissions Reduction (TPY)</b>	<b>Annualized Cost (\$/year)</b>	<b>Cost Effectiveness (\$/ton)</b>
H-8601	52	37.96	388,850	10,273
H-8602	15	10.95	232,286	21,266
H-8603	12	8.76	227,532	25,974
H-8801	32	23.36	316,528	13,550
B-0008	169	123.37	752,063	6,096

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

ULNB

The next most efficient control is ULNB. This option has been proposed as BACT at an emission rate of 0.035 lb/MMBTU.

Source	Uncontrolled Emissions (TPY)	Emissions Reduction (TPY)
H-8601	52	29
H-8602	15	8
H-8603	12	7
H-8801	32	18
B-0008	169	95

5. Select BACT/ Document the Selection is BACT

Based on this review, BACT is proposed as ULNB at 0.035 lb/MMBTU. The RBLC and recently issued permits in attainment areas were reviewed for recent determinations. The reviewed determinations resulted in BACT determinations requiring ULNB with emissions ranging from 0.06 lb/MMBTU to 0.035 lb/MMBTU. Therefore, the proposed control is acceptable as BACT.

CO

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling CO emissions from the heaters/boiler.

Technology
Good Combustion Practice
Catalytic Oxidation
Thermal Oxidation

Good Combustion Practice

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

Good combustion practice is the industry standard for CO control of refinery process heaters and boilers. CO emissions are controlled by maintaining various operational combustion parameters.

The combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. These designs result in emissions of 0.0824 lb/MMBTU.

### Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and at a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 feet per second (fps) to 30 fps. Catalytic oxidizers typically operate at 650 °F to 1,000 °F.

Environmental impacts and costs associated with the operation of oxidation catalysts to control CO emissions include increased downtime required for catalyst washing and hazardous material handling concerns during catalyst disposal.

Catalytic oxidizers cannot be used on waste gas streams containing significant amounts of particulate matter. Particulate deposits foul the catalyst and prohibit oxidation. High temperatures can also accelerate catalyst deactivation. Short-term temperatures above 1,500 °F can cause near total loss of catalyst activity.

### Thermal Oxidation

Thermal oxidizers combine temperature, time, and turbulence to achieve complete combustion. Thermal oxidizers are equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO. The waste gas is passed through burners, where the gas is heated above its ignition temperature. Additional fuel is required to reach this higher temperature. The hot gases then pass through one or more residence chambers to ensure complete combustion.

Thermal oxidizers require operating temperatures in the 1,200 °F to 2,000 °F range to ensure conversion of CO to CO<sub>2</sub>. The combustion process occurs in two separate stages: (1) the combustion of fuels and (2) the combustion of pollutants. The combustion process in the first stage is an extremely rapid and irreversible chemical reaction. The oxygen supplied by the primary air may be in excess or obtained directly from the process gas stream. In the second stage of the process, the heated gases from the burners pass through residence chambers, where the CO is oxidized. Efficiency is dependent on residence time, heating value of the gas stream, and operating temperatures.

Flame quenching can be problematic with thermal oxidation. To avoid noncombustible mixtures, the entire amount of waste gas and fuel cannot be mixed at the burner. Therefore, an inordinate amount of fuel would be required to bring the entire waste gas stream into combustible limits, resulting in burner flame quenching. Only a fraction of the waste stream is mixed at the burner, and the remaining waste is mixed with the hot gases downstream of the flame. Incomplete oxidation can occur when there is inadequate mixing of the waste gas stream

and the hot downstream gases.

2. Eliminate Technically Infeasible Options

Catalytic oxidizers require exhaust gas temperatures ranging from 650 °F to 1,000 °F. Therefore, catalytic oxidation could be considered technically infeasible for the control of CO emissions from process heaters H-8601, H-8603, H-8801, and gas-fired boiler B-0008, which have exhaust temperatures ranging from 350 °F to 600 °F. However, for a conservative review CO oxidation for these heaters was reviewed. Since the exhaust temperature of process heater H-8602 is approximately 700 °F, catalytic oxidation remains a technically feasible control option for this heater.

Although thermal oxidization was not found to be used as a control device for these types of sources, it remains technically feasible.

3. Rank Remaining Options

Technology	Typical Control Range (% Removal)	Typical Emission Level
Catalytic Oxidation (Heater H-8602 only)	90	0.0082
Thermal Oxidation	90	0.0082
Good Combustion Practice	-	0.0824

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

The remaining technologies are reviewed on a case-by-case basis taking into consideration energy, environmental, and economic impacts beginning with the top option. If the top option is not selected as BACT, the next most effective control is evaluated.

Catalytic Oxidation

Oxidation catalysts can increase emissions of acid gases and cause heat input and power penalties. Sulfur and other compounds in the exhaust may foul the catalyst, leading to decreased activity. The catalyst can be chemically washed to restore its effectiveness, but eventually, irreversible degradation occurs. Potential environmental impacts and maintenance issues are not considered unreasonable.

Because catalytic oxidation is considered to be a technically feasible add-on control option and not eliminated due to environmental impacts, its cost effectiveness was calculated. The cost effectiveness was evaluated for the proposed process heaters and boiler based on the “EPA Air Pollution Control Cost Manual,” Sixth Edition and vendor cost estimates.



Source	Uncontrolled Emissions (TPY)	Emissions Reduction (TPY)	Annualized Cost (\$/year)	Cost Effectiveness (\$/ton)
H-8601	53.78	48.40	586,152	12,110
H-8602	15.88	14.4	407,993	28,333
H-8603	11.91	10.72	367,239	34,261
H-8801	32.48	29.23	730,595	24,993
B-0008	174.39	156.95	2,587,915	16,488

The RBLC and recently issued permits in attainment areas were reviewed for recent determinations. The reviewed determinations did not result in catalytic oxidation as BACT. Therefore, based on the associated costs and recent determinations, catalytic oxidation is eliminated from consideration.

Thermal Oxidation

Thermal oxidation requires that the exhaust stream temperature to be increased so that oxidation will occur. This increase would be accomplished by the combustion of additional fuel. This fuel combustion will result in additional combustion emissions. These additional environmental impacts are not considered unreasonable.

Because thermal oxidation is considered to be a technically feasible add-on control option and not eliminated due to environmental impacts, its cost effectiveness was calculated. The cost effectiveness was evaluated for the proposed process heaters and boiler based on the “EPA Air Pollution Control Cost Manual,” Sixth Edition and vendor cost estimates.

Source	Uncontrolled Emissions (TPY)	Emissions Reduction (TPY)	Annualized Cost (\$/year)	Cost Effectiveness (\$/ton)
H-8601	53.78	48.40	986,586	20,384
H-8602	15.88	14.29	578,688	40,496
H-8603	11.91	10.72	482,936	45,050
H-8801	32.48	29.23	1,362,556	46,615
B-0008	174.39	156.95	3,670,590	23,387

The RBLC and recently issued permits in attainment areas were reviewed for recent determinations. The reviewed determinations did not result in thermal oxidation as BACT. Therefore, based on the associated costs and recent determinations, thermal oxidation is eliminated from consideration.

5. Select BACT/ Document the Selection is BACT

Based on this review, BACT is proposed as good combustion practice at 0.0824 lb/MMBTU for the process heaters and boiler. The RBLC and recently issued permits were reviewed for recent determinations. The reviewed determinations resulted in BACT determinations requiring

combustion control with emissions ranging from 0.082 lb/MMBTU to 0.084 lb/MMBTU with the exception of some California determinations. However, it is understood that California BACT determinations are equivalent to Lowest Achievable Emission Rate (LAER). Therefore, the proposed control is acceptable as BACT.

PM<sub>10</sub>

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling PM<sub>10</sub> emissions from the heaters/boilers.

<b>Technology</b>
Good Combustion Practice
Wet Gas Scrubber
Electrostatic Precipitator
Cyclone
Baghouse/Fabric Filters

Good Combustion Practice

By maintaining the heaters in good working order per manufacturer’s specifications, emissions of PM<sub>10</sub> are reduced.

Wet Gas Scrubber

A wet gas scrubber uses gas/liquid contacting to remove particles by inertial impaction and/or condensation of liquid droplets on particles in the gas stream.

Electrostatic Precipitator (ESP)

An ESP uses an electric field to charge and collect particles from an effluent gas stream. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected as they are attracted to oppositely charged electrodes.

Cyclone

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles, in a spinning motion, proceed downward the heavier material hits the outside wall and drops to the bottom and is collected. The cleaned gas escapes through an inner tube.

Baghouse/Fabric Filter

A baghouse is a large metal housing containing many fabric bags. A large suction or vacuum-producing unit creates a partial vacuum within the housing which pulls in dirty air from the cyclone unit and filters out the dirt with the bags.

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

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

5. Select BACT/Document the Selection is BACT

Based on this review, BACT is proposed as limiting the four proposed process heaters (H-8601, H-8602, H-8603, and H-8801) and the gas-fired boiler (B-0008) to refinery fuel gas or pipeline quality natural gas, good combustion practice, and emissions of 0.0075 lb/MMBTU. The RBLC database lists this option as the most prevalent form of BACT for controlling PM<sub>10</sub> emissions from gas-fired process heaters and boilers. Therefore, the fuel limits and good combustion practices with a limit of 0.0075 lb/MMBTU are acceptable as BACT.

VOC

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling VOC emissions from the heaters/boilers.

<b>Technology</b>
Good Combustion Practice
Catalytic Oxidation

Good Combustion Practice

Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, VOC emissions are minimized.

The design of modern, efficient combustion equipment is such that there is adequate turbulence in the flue gas to ensure good mixing, a high temperature zone (greater than 1,800 °F) to complete burnout, and sufficient residence time at the high temperature (one to two seconds).

Good combustion practice is the industry standard for VOC control of refinery process heaters and boilers. VOC emissions are controlled by maintaining various operational combustion parameters. The combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. These designs result in controlled emissions of 0.0054 lb/MMBTU.

Catalytic Oxidation

The formation of VOC in combustion units depends primarily on the efficiency of combustion. Inefficient combustion leads to the formation of aldehydes, aromatic carbon compounds, and various other organic compounds by several mechanisms. Catalytic oxidation decreases VOC emissions by facilitating the complete combustion of organic compounds to water and carbon dioxide.

Catalytic oxidation allows complete oxidation to take place at a faster rate and at a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 feet per second (fps) to 30 fps. Catalytic oxidizers typically operate at 650 °F to 1,000 °F.

Environmental impacts and costs associated with the operation of oxidation catalysts to control VOC emissions include increased downtime required for catalyst washing and hazardous material handling concerns during catalyst disposal.

Catalytic oxidizers cannot be used on waste gas streams containing significant amounts of particulate matter. Particulate deposits foul the catalyst and prohibit oxidation. High temperatures can also accelerate catalyst deactivation. Short-term temperatures above 1,500 °F can cause near total loss of catalyst activity.

2. Eliminate Technically Infeasible Options

Catalytic oxidizers require exhaust gas temperatures ranging from 650 °F to 1,000 °F. Therefore, catalytic oxidation is technically infeasible for the control of VOC emissions from the process heaters H-8601, H-8603, and H-8801, and gas-fired boiler B-0008, which have exhaust temperatures ranging from 350 °F to 600 °F. Since the exhaust temperature of process heater H-8602 is approximately 700 °F, catalytic oxidation remains a technically feasible control option.

3. Rank Remaining Options

<b>Technology</b>	<b>Control Efficiency (%)</b>
Catalytic Oxidation (H-8602 only)	90
Good Combustion Practice	Base Case

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

Oxidation catalysts can increase emissions of acid gases and cause heat input and power penalties. Sulfur and other compounds in the exhaust may foul the catalyst, leading to decreased activity. The catalyst can be chemically washed to restore its effectiveness, but eventually, irreversible degradation occurs. Additionally, VOC emissions are significantly lower than CO, which was eliminated due to associated costs, therefore, associated costs will increase for VOC control. Furthermore, the RBLC has no record of this technology being required as VOC control for heaters or boilers.

Therefore, catalytic oxidation is eliminated from consideration for VOC control from process heater H-8602 due to its associated costs and no history of being applied as BACT.

5. Select BACT/ Document the Selection is BACT

Based on this review, good combustion practices with emissions of 0.0054 lb/MMBTU are proposed as BACT for the process heaters and boiler. The RBLC database lists this option as the most prevalent form of BACT for controlling VOC emissions from process heaters and boilers. BACT limits from these determinations were consistently in the 0.0054 range. Therefore, good combustion practices with the emission limit of 0.0054 lb/MMBTU are acceptable as BACT.

SO<sub>2</sub>

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling SO<sub>2</sub> emissions from the heaters/boiler.

<b>Technology</b>
Fuel Specification: Low Sulfur Fuels
Caustic Scrubber
Limestone Slurry Scrubber

Fuel Specification

Nearly all of the sulfur contained in the fuel being combusted will be converted to SO<sub>2</sub>, therefore, by limiting the sulfur content of the fuel SO<sub>2</sub> emissions are reduced.

Caustic Scrubber

The absorption of SO<sub>2</sub> with caustic is the simplest method of flue gas desulfurization. In this scrubbing system, the flue gas and a caustic solution flow counter-current to each other. A dual

alkali scrubber system utilizes a solution of sodium sulfite ( $\text{Na}_2\text{O}_3\text{S}$ ) and sodium hydroxide ( $\text{NaOH}$ ) to provide absorption and neutralization of  $\text{SO}_2$  within the spray tower. The sulfur reacts with the caustic solution and is stripped out of the flue gas stream. Since both sodium sulfite and sodium hydroxide are soluble in water, no precipitation occurs within the scrubber, as with lime scrubbing. However, water contamination issues arise with the disposal of large volumes of sodium sulfite and sodium sulfate solution. Lime or limestone is added to the scrubber effluent along with additional sodium hydroxide or soda ash to precipitate the sulfite/sulfate ions and regenerate the sodium hydroxide.

Limestone Slurry Scrubber

Limestone slurry scrubbing systems have been applied to coal fired power plants for flue gas desulfurization. In this scrubbing system, the flue gas and limestone slurry flow counter-current to each other. The limestone, otherwise known as calcium carbonate ( $\text{CaCO}_3$ ), reacts with the  $\text{SO}_2$  forming calcium sulfate ( $\text{CaSO}_4$ ).

2. Eliminate Technically Infeasible Options

All listed controls are technically feasible.

3. Rank Remaining Options

Technology	Control Efficiency (%)
Limestone Slurry Scrubber	95
Caustic Scrubber	95
Fuel Specification: Low Sulfur Fuels (160 ppmv)	Base Case

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

Limestone Slurry Scrubber/Caustic Scrubber

No energy/environmental impacts were identified to preclude these options from review.

Because these options are considered to be a technically feasible add-on controls and not eliminated due to environmental impacts, the cost effectiveness for each was calculated. The cost effectiveness for each option was evaluated for the proposed process heaters and boiler based on the “EPA Air Pollution Control Cost Manual,” Sixth Edition and vendor cost estimates.

<b>Limestone Slurry Scrubber</b>				
<b>Source</b>	<b>Uncontrolled Emissions (TPY)</b>	<b>Emissions Reduction (TPY)</b>	<b>Annualized Cost (\$/year)</b>	<b>Cost Effectiveness (\$/ton)</b>
H-8601	26.56	25.23	250,534	9,930
H-8602	7.84	7.45	137,919	18,513
H-8603	5.88	5.59	119,563	21,389
H-8801	0.23	0.22	252,957	1,149,805
B-0008	86.14	81.83	589,494	7,204

<b>Caustic Scrubber</b>				
<b>Source</b>	<b>Uncontrolled Emissions (TPY)</b>	<b>Emissions Reduction (TPY)</b>	<b>Annualized Cost (\$/year)</b>	<b>Cost Effectiveness (\$/ton)</b>
H-8601	26.56	25.23	316,689	12,552
H-8602	7.84	7.45	189,191	25,395
H-8603	5.88	5.59	152,903	27,353
H-8801	0.23	0.22	371,695	1,689,523
B-0008	86.14	81.83	659,951	8,064

The RBLC and recently issued permits in attainment areas were reviewed for recent determinations. The reviewed determinations did not result in limestone slurry scrubbing or caustic scrubbing as BACT. Therefore, based on the associated costs and recent determinations, they are eliminated from consideration.

5. Select BACT

Based on this review, limiting the H<sub>2</sub>S content of the refinery fuel-gas fired in three of the four proposed process heaters (H-8601, H-8602, and H-8603) and the gas-fired boiler (B-0008) to a maximum of 0.10 grains/dscf (160 ppm<sub>v</sub>/0.0407 lb/MMBTU) and limiting heater H-8801 to pipeline quality natural gas (0.0006 lb/MMBTU) are proposed as BACT for the process heaters and boiler.

6. Document the Selection is BACT

The RBLC database lists this option as the most prevalent form of BACT for controlling SO<sub>2</sub> emissions from gas-fired process heaters and boilers. Therefore, the SO<sub>2</sub> content and pipeline quality natural gas limits which are equivalent to 0.0407 lb/MMBTU and 0.0006 lb/MMBTU, respectively, are acceptable as BACT.

**BACT Analysis for the Flare**

NO<sub>x</sub>

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling NO<sub>x</sub> emissions from the flare.

<b>Technology</b>
Good Combustion Practice
Fuel Specification: Pipeline Quality Natural Gas

Good Combustion Practice

Implementing good combustion practice ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, NO<sub>x</sub> emissions are minimized.

This control option emphasizes NO<sub>x</sub> control by means of maintaining various combustion operational parameters. Good combustion practice is the industry standard for NO<sub>x</sub> control of flares. Refiners control NO<sub>x</sub> emissions by maintaining various operational combustion parameters.

Fuel Specification: Pipeline Quality Natural Gas

Due to the characteristically low fuel nitrogen content of natural gas, NO<sub>x</sub> formation due to the reaction of fuel-bound nitrogen compounds with oxygen is less than the NO<sub>x</sub> formation associated with the firing of other potential flare pilot fuels. Thus, a fuel specification of pipeline quality natural gas for the proposed flare pilot provides an inherent reduction in NO<sub>x</sub> emissions as compared to other potential fuel sources

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

Since a single method of control was identified to control NO<sub>x</sub> emissions, no ranking and evaluation of various control methods is needed. The applicant has proposed good combustion practice and limiting the pilot fuel to pipeline grade natural gas with emissions of 0.068 lb/MMBTU as BACT. The RBLC database lists this option as the most prevalent form of BACT



for controlling NO<sub>x</sub> emissions from the flare pilot. Therefore, these limits are acceptable as BACT.

CO

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling CO emissions from the flare.

<b>Technology</b>
Good Combustion Practice

Good Combustion Practice

Implementing good combustion practice ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, CO emissions are minimized.

This control option emphasizes CO control by means of maintaining various combustion operational parameters. Good combustion practice is the industry standard for CO control of flares.

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

Since a single method of control was identified to control CO emissions, no ranking and evaluation of various control methods is needed. The applicant has proposed good combustion practice and emissions of 0.37 lb/MMBTU as BACT. The RBLC database lists this option as the most prevalent form of BACT for controlling CO emissions from flare pilot. Therefore, good combustion practices and an emission limit of 0.37 lb/MMBTU are acceptable as BACT.

SO<sub>2</sub>

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling SO<sub>2</sub> emissions from the flare.

<b>Technology</b>
Fuel Specification – Pipeline Quality Natural Gas

Fuel Specification – Pipeline Quality Natural Gas

Due to the characteristically low fuel sulfur content of pipeline natural gas, SO<sub>2</sub> formation is less than the SO<sub>2</sub> formation associated with the firing of other potential flare pilot fuels. Thus, a fuel specification of pipeline quality natural gas for the proposed flare pilot provides an inherent reduction in SO<sub>2</sub> emissions, as compared to other potential fuel sources.

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

Since a single method of control was identified to control SO<sub>2</sub> emissions, no ranking and evaluation of various control methods is needed. The applicant has proposed pipeline quality natural gas as BACT. The RBLC database does not contain determination for this pollutant. Therefore, based on the inherently low SO<sub>2</sub> emissions associated with pipeline quality natural gas, it is acceptable as BACT.

PM<sub>10</sub>

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling SO<sub>2</sub> emissions from the flare.

<b>Technology</b>
Smokeless Operation

Smokeless Operation

The flare that is designed to be smokeless during normal operations will reduce PM<sub>10</sub> emissions from the proposed flare.

2. Eliminate Technically Infeasible Options
3. Rank Remaining Options
4. Evaluate Remaining Options (determine most efficient based on economic analysis and energy/environmental impacts)
5. Select BACT

6. Document the Selection is BACT

Since a single method of control was identified to control PM<sub>10</sub> emissions, no ranking and evaluation of various control methods is needed. The applicant has proposed a smokeless flare as BACT. The RBLC database only contains fuel limits as BACT for this pollutant. Therefore, the smokeless operation and pipeline quality natural gas limits are acceptable as BACT.

VOC

1. Identify All Available Control Technologies

The following is a list of control technologies which were identified for controlling VOC emissions from the flare.

<b>Technology</b>
Good Combustion Practice

Good Combustion Practice

Implementing good combustion practice ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, VOC emissions are minimized.

This control option emphasizes VOC control by means of maintaining various combustion operational parameters. Good combustion practice is the industry standard for VOC control of flares.

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

Since a single method of control was identified to control VOC emissions, no ranking and evaluation of various control methods is needed. The applicant has proposed good combustion practice as BACT. The RBLC database only contains fuel limits as BACT for this pollutant. Therefore, good combustion practice is acceptable as BACT.

**BACT Analysis for Equipment Leaks**

1. Identify All Available Control Technologies

VOC

<b>Technology</b>
Petroleum Refinery NSPS – 40 CFR 60, Subpart GGG Monitoring
Petroleum Refinery NESHAPs – 40 CFR 63, Subpart CC Monitoring

Petroleum Refinery NSPS – 40 CFR 60, Subpart GGG

The petroleum refinery NSPS requires monthly monitoring of pumps and valves to detect leaks, provisions for monitoring the seal system or barrier fluid system of compressors, and provisions for repairing equipment determined to be leaking. The definitions of what constitute equipment leaks are not reduced based on the amount of time the equipment has been in service. Leak detection readings for valves consistently below the leak threshold can result in a decrease in the monitoring frequency.

Petroleum Refinery NESHAPs – 40 CFR 63, Subpart CC Monitoring

The requirements of the petroleum refinery NESHAP (hereafter referred to as the Refinery MACT) include monthly monitoring of pumps and valves to detect leaks, provisions for monitoring the seal system or barrier fluid system of compressors, and provisions for repairing equipment determined to be leaking. The MACT also provides a definition of the VOC concentration level that constitutes equipment leaks. Leak detection readings consistently below the leak threshold can result in a decrease in the monitoring frequency.

2. Eliminate Technically Infeasible Options

Both options are technically feasible.

3. Rank Remaining Options

<b>Technology</b>	<b>Control Efficiency (%)</b>
Petroleum Refinery NESHAPs – 40 CFR 63, Subpart CC Monitoring	91 – 95
Petroleum Refinery NSPS – 40 CFR 60, Subpart GGG Monitoring	81 – 88

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

Neither option can be eliminated based on economic or energy/environmental impacts.

5. Select BACT

Based on this review, BACT is proposed as inspect, monitor, and repairing equipment components in accordance with the requirements of the Refinery MACT.

6. Document the selection is BACT

The RBLC database lists leak detection and repair (LDAR) options as the most prevalent form of BACT for controlling fugitive VOC emissions from process equipment. While the determinations do not specifically refer to a regulation, the Refinery MACT standards and the standards under the MACT equal or exceed BACT. While this MACT was created for the control of hazardous air pollutant (HAPs), this method of control is equally effective for VOC. Therefore, meeting the Refinery MACT for the fugitive equipment sources is acceptable as BACT.

**BACT Analysis for Tanks**

VOC

1. Identify All Available Control Technologies

<b>Technology</b>
Refinery MACT, 40 CFR Part 63 Subpart CC

Refinery MACT

The Refinery MACT (40 CFR Part 63 Subpart CC) requires internal or external floating roof tanks with proper seals or a closed vent system and control device that reduces HAP emissions by 95%.

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

Since the tanks will be subject to the Refinery MACT standards and the standards under the MACT exceed BACT and the RBLC database lists floating roofs as the most prevalent form of BACT, the applicability to the Refinery MACT which requires floating roofs and seals is acceptable as BACT.

**BACT Analysis for the Cooling Tower**

VOC

1. Identify All Available Control Technologies

<b>Technology</b>
Hydrocarbon Monitoring

Hydrocarbon Monitoring

Hydrocarbon monitoring includes periodic sampling of a stream of cooling tower water to determine VOC concentration and indications of possible process leaks.

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

Since a single method of control was identified to control VOC emissions, no ranking and evaluation of various control methods is needed. The applicant has proposed hydrocarbon monitoring as BACT. The RBLC database lists monitoring of VOC concentrations in the cooling water as the most prevalent form of BACT. Therefore, hydrocarbon monitoring is acceptable as BACT.

PM<sub>10</sub>

1. Identify All Available Control Technologies

<b>Technology</b>
Limit Total Dissolved Solids (TDS)
Drift Eliminator

Limit Total Dissolved Solids (TDS)

Imposing a limit on the TDS in the cooling tower water would reduce the amount of particulate that can potentially become entrained in the water leaving the tower and therefore, the amount of particulate emissions from the tower.

Drift Eliminators

The magnitude of cooling tower drift loss is influenced by the quantity and size of the droplets formed in the cooling tower. The number and size of the droplets is determined by the tower fill design, air and water patterns, tower maintenance, and operation levels. Large drift droplets settle out of the tower exhaust air stream and deposit near the tower. Other drift droplets may evaporate before being deposited in the area near the tower.

To reduce drift from cooling towers, drift eliminators are typically incorporated into the tower design to remove as many droplets as possible from the air stream before the stream exits the tower. Drift eliminators function on the principle of inertial separation caused by directional changes while passing through the eliminators. Advances in drift eliminator technology have further increased the potential for drift reduction. Drift eliminators are the most common control for PM<sub>10</sub> emissions from cooling towers.

2. Eliminate Technically Infeasible Options

Limits on TDS is not feasible because this is process limited.

3. Rank Remaining Options

Technology	Control Efficiency (%)
Drift Eliminator	99.998

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

This option cannot be eliminated based on economic or energy/environmental impacts.

5. Select BACT

Based on this review, BACT is proposed as drift eliminators.

6. Document the Selection is BACT

The RBLC database lists drift eliminators as the most prevalent form of BACT for controlling PM<sub>10</sub> emissions from cooling towers. Therefore, drift eliminators are acceptable as BACT.

**BACT Analysis for the Wastewater**

VOC

1. Identify All Available Control Technologies

<b>Technology</b>
Refinery MACT, 40 CFR Part 63 Subpart CC or NESHAPS, 40 CFR Part 61 Subpart FF

Petroleum Refinery NESHAPs – 40 CFR 63, Subpart CC Monitoring

The requirements of the Refinery MACT includes monthly monitoring of pumps and valves to detect leaks, provisions for monitoring the seal system or barrier fluid system of compressors, and provisions for repairing equipment determined to be leaking. The MACT also provides a definition of the VOC concentration level that constitutes equipment leaks. Leak detection readings consistently below the leak threshold can result in a decrease in the monitoring frequency.

Petroleum Refinery NSPS – 40 CFR 60, Subpart GGG

The petroleum refinery NSPS requires monthly monitoring of pumps and valves to detect leaks, provisions for monitoring the seal system or barrier fluid system of compressors, and provisions for repairing equipment determined to be leaking. The definitions of what constitute equipment leaks are not reduced based on the amount of time the equipment has been in service. Leak detection readings for valves consistently below the leak threshold can result in a decrease in the monitoring frequency.

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

Since the wastewater system will be subject to the Refinery MACT (which requires compliance with NESHAPs Subpart FF) standards and the standards under the MACT exceed BACT and the RBLC database lists monitoring as the most prevalent form of BACT, the applicability to the Refinery MACT is acceptable as BACT.

**Air Quality Impacts**

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



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

Pollutant	Averaging Period	SIL ( $\mu\text{g}/\text{m}^3$ )
NO <sub>x</sub>	annual	1
TSP/PM <sub>10</sub>	annual	1
	24-hour	5
SO <sub>2</sub>	Annual	1
	24-hour	5
	3-hour	25
CO	8-hour	500
	1-hour	2,000
O <sub>3</sub>	*	*

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

**Significant Net Emission Increase**

In order to determine if a project at a PSD major source is subject to PSD review, a facility must perform a PSD netting analysis for the proposed project. The netting demonstration was not shown in Section VI, PSD Review, since the applicant did not propose to net out for any pollutant. However, in order to determine if an ROI results from the project, the significant net emission increase must be determined. Therefore, it is included here.

The significant netting analysis requires a facility to include any increase or decrease in actual emissions at the source that are considered contemporaneous with the particular change. To be contemporaneous, the increase or decrease must have occurred within a period beginning 3 years before the date construction is expected to commence on the modification.

Conoco performed a PSD netting analysis based on suggested emissions netting procedures in the Draft EPA New Source Review (NSR) Workshop Manual and DEQ guidance. A six-step procedure is used for determining the net emissions change and is summarized below.

1. Emission Increases From the Proposed Project - Determine the emission increases from the proposed project. If increases are significant, proceed; if not, the project is not subject to PSD review.

2. Contemporaneous Period - Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed project.
3. Emissions Increases and Decreases During the Contemporaneous Period - Determine which emissions units at the facility experienced (or will experience, including any proposed decreases resulting from the proposed project) a creditable increase or decrease in emissions during the contemporaneous period.
4. Creditable Emissions Changes - Determine which contemporaneous emissions changes are creditable.
5. Amount of the Emissions Increase and Decrease - Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.
6. PSD Review - Sum all contemporaneous and creditable increases and decreases with the emissions changes from the proposed project to determine if a significant net emissions increase will occur.

The netting analysis procedure allows the use of contemporaneous creditable increases and decreases. However, Conoco has included only contemporaneous and creditable emissions increases in this netting analysis, therefore, emissions decreases will remain available for future PSD netting analyses. VOC netting was not conducted since emissions resulted in a significant impact. The significant impact for VOC is defined as VOC emissions above 100 TPY.

Contemporaneous and creditable emissions increases included in the PSD netting analysis are based on issued permits and emission increases for projects not requiring a permit. The table on the following page summarizes the contemporaneous and creditable emissions increases included in the project PSD netting analysis.

Permit Date	Permit Number	Description	Emissions Increases (tpy)			
			SO <sub>2</sub>	NO <sub>x</sub>	PM <sub>10</sub>	CO
07/30/99	96-280-O (M-1)	No. 4 FCCU Wet Gas Compressor Replacement Project	35.4	26.1	1.3	79.4
09/01/99 <sup>a</sup>	--	Fall 1999/Spring 2000 Turnaround	1.54 <sup>b</sup>	37.87 <sup>c</sup>	1.78 <sup>b</sup>	10.24 <sup>b</sup>
09/15/99	97-286-O (M-1)	H-6006 Preflash Heater	18.71 <sup>d</sup>	11.32 <sup>d</sup>	3.21 <sup>d</sup>	34.9 <sup>d</sup>
12/16/99	90-085-O (M-1)	Ponca City Terminal, Truck Rack Loading Flare, T-4, and T-5	--	0.65	--	4.62
03/29/00	88-115-AD (M-2)	Isomerization Unit Change	2.08	2	0.07	3.5
10/01/00 <sup>a</sup>	2000-206-C	Vapor Recovery Unit Expansion/No. 4 FCCU Turnaround	0.03	94.68	0	14.36
10/01/00 <sup>a</sup>	--	No. 3 Amine Unit Installation	13.48 <sup>e</sup>	61.99 <sup>c</sup>	5.69 <sup>e</sup>	37.44 <sup>e</sup>
08/23/01	98-169-C (M-2)	No. 5 FCCU VRU Expansion/Coker Gas Plant Construction	16.85	24.89 <sup>f</sup>	14.55	75.95 <sup>f</sup>
08/31/01	2001-189-C	Santa Fe Aviation Gasoline Rail Car Loading Rack Flare	0.0001	0.2374	0.0018	0.4739
10/01/01	2001-172-C	No. 7 Coker Flare Gas Recovery Project	10.04	--	--	--
11/01/01 <sup>g</sup>	--	Naptha In-Line Caustic Treating	20.57 <sup>b</sup>	11.73 <sup>b</sup>	2.63 <sup>b</sup>	0.96 <sup>b</sup>
12/01/01 <sup>g</sup>	--	Naptha Booster Pumps	0.96 <sup>b</sup>	10.45 <sup>b</sup>	0.4 <sup>b</sup>	4.14 <sup>b</sup>

Permit Date	Permit Number	Description	Emissions Increases (tpy)			
			SO <sub>2</sub>	NO <sub>x</sub>	PM <sub>10</sub>	CO
01/03/02	2001-305-C	No. 3 Catalytic Reformer Unit Modification	39.09	--	5.44	14.65
03/01/02 <sup>g</sup>	--	Butamer TA	0.53 <sup>b</sup>	13.29 <sup>b</sup>	0.86 <sup>b</sup>	3.23 <sup>b</sup>
04/01/02 <sup>g</sup>	--	No. 6 HDT Retray	0.03 <sup>b</sup>	0.57 <sup>b</sup>	0.04 <sup>b</sup>	0.49 <sup>b</sup>
07/01/03 <sup>g</sup>	--	No. 1 CTU Bottoms Upgrading	10 <sup>b</sup>	100 <sup>b</sup>	8 <sup>b</sup>	50 <sup>b</sup>
07/01/03 <sup>g</sup>	--	No. 4 CTU Project	40 <sup>b</sup>	40 <sup>b</sup>	15 <sup>b</sup>	100 <sup>b</sup>
07/01/03 <sup>g</sup>	--	Installation of Temporary Compressor	0.04 <sup>b</sup>	1.82 <sup>b</sup>	1.82 <sup>b</sup>	3.21 <sup>b</sup>
11/01/03	--	Low Sulfur Gasoline Project	128.1	143.88	27.43	299.11
<b>Total</b>			<b>337.45</b>	<b>581.48</b>	<b>88.22</b>	<b>736.67</b>

- a. Estimated operation date determined from permit memorandum for 2000-206-C.
- b. Emissions increases provided by Conoco for projects not requiring a permit.
- c. Emissions increase based on netting analysis performed in permit memorandum for 2000-206-C.
- d. The H-6006 Preflash Heater began operation in December 1997. The shown permit revision incorporates associated emissions increases not originally included in the project netting. These emissions increases were derived from subtracting actual emissions in 1998 (the only full year of operation) from the permit emission limits.
- e. Emissions increases based on permit application.
- f. The permit memorandum for 98-169-C (M-2) incorrectly calculates the project increases for NO<sub>x</sub> and CO emissions. The increases shown here correct this miscalculation.
- g. Estimated emissions based on information provided by Conoco.

**Description of Air Quality Dispersion Model and Methodology**

Description of Air Quality Dispersion Model

The Industrial Source Complex Short-Term Version 3 (ISCST3) model was used to estimate maximum ground-level, off-property concentrations of the criteria pollutants. The modeling analysis was performed using the regulatory default option, which includes stack heights adjusted for stack-tip downwash, buoyancy-induced dispersion, and final plume rise. Ground-level concentrations occurring during “calm” wind conditions were calculated by the model using the calm processing feature. Regulatory default values for wind profile exponents and vertical potential temperature gradients were used, since no representative on-site meteorological data are available. Per U.S. EPA modeling requirements, direction-specific building dimensions were used for both the Schulman-Scire and the Huber-Snyder downwash algorithms.

The Conoco fenceline receptors are located proximate to both emission sources and buildings and may be located in cavity regions. This situation raises concern about the estimation of modeled concentrations at receptors within the “cavity” region of buildings located downwind of the emission plumes. Field studies have demonstrated that ground-level concentrations within a building cavity can be significantly higher when compared to those measured outside of the cavity. The current version of ISCST3 is not capable of determining cavity concentrations. Therefore, ISCST3 modeling results at receptors located within a cavity may be underestimated under certain dispersion conditions.

ISC-PRIME was used for receptors identified in ISCST3 model as being located in a cavity region. The ISC-PRIME model incorporates more accurate plume rise and building downwash algorithms into the model. Since this modeling analysis involves a large number of sources and buildings, a recompiled version of ISC-PRIME was used (dated 98069). This model was used to estimate ground-level concentrations at receptors identified in the ISCST3 model runs as “*Source-receptor combinations for which calculations may not be performed.*”

#### GEP Stack Height and Plume Downwash

The emissions units at the Refinery have been evaluated based on the proximity to nearby structures. The purpose of this evaluation is to determine if stack discharges may become caught in the turbulent wakes of these structures. Wind blowing around a building creates zones of turbulence. The current version of the ISCST3 dispersion model provides for a revised treatment of building wake effects which, for certain emissions units, uses wind direction-specific building dimensions following the algorithms developed by Schulman and Hanna. The minimum stack height not subject to the effects of downwash is defined by the formula:

$$G = H + 1.5L$$

Where: G = Minimum Good Engineering Practice (GEP) stack height  
H = Height of the structure  
L = Lesser dimension (height or projected width of structure)

This equation is limited to stacks located within 5L of the structure. Stacks located at distances greater than 5L are not subject to the wake effects of the structure. If a given source has more than one stack with the 5L range, the above equation must be successively applied to each stack. If more than one structure is involved, the equations must be successively applied to each structure.

Direction-specific building dimensions and the dominant downwash structure parameters used as input to the dispersion models were determined using the *BREEZE-WAKE/BPIP* software. This software incorporates the algorithms of the U.S. EPA-sanctioned Building Profile Input Program (BPIP) latest version (dated 95086). BPIP is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, the Building Downwash Guidance document and other related documents.

The output from the BPIP/BPIP - PRIME downwash analyses lists the names and dimensions of the structures as well as the emissions unit locations and heights. In addition, the output contains a summary of the dominant structure for each emissions unit, considering all wind directions, and the actual building height and projected widths for all wind directions. This information is then incorporated into the data files for the ISCST3/ISC-PRIME models.

### Land Use Coefficient

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

### Terrain

The ISCST3 and ISC PRIME models have the option to calculate concentrations based on flat or elevated terrain. For this modeling analysis, elevated terrain is used. The receptor terrain elevations entered into the models are the highest elevations extracted from USGS 1:24,000 scale (7.5 minute series) digital elevation model (DEM) data of the area surrounding the Refinery. DEM is a digital file consisting of terrain elevations for ground positions at regularly spaced intervals. For each receptor, the maximum terrain elevation associated with the four DEM points surrounding the receptor is selected for the receptor elevations. DEM data was also used for the base elevations of Refinery sources and buildings.

### Meteorological Data

The ISCST3 and ISC-PRIME air dispersion modeling was performed using 1986 through 1988 reprocessed meteorological data based on surface observations taken from Wichita, Kansas, [National Weather Service Station (NWS) station number 3928] with upper air measurements from Oklahoma City, Oklahoma, (NWS station number 13967). The 1990 and 1991 preprocessed meteorological data are based on surface observations taken from Wichita, Kansas and upper air measurements from Norman, Oklahoma (NWS station number 3948). The anemometer height at the Wichita, Kansas, NWS station during the period of interest was 10.06 meters.

### Receptor Grid

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

1. A Fenceline Grid containing 100 meter-spaced receptors along the Refinery fenceline and in areas within Conoco's fenceline that are open to the public or operated by non-Conoco employees
2. A Fine Grid containing 100 meter-spaced receptors, extending approximately 1.0 km from the fenceline exclusive of the receptors within the Refinery fenceline

3. A Medium Grid containing 500 meter-spaced receptors, extending 5 km from the fenceline exclusive of receptors in the fine grid
4. A Coarse Grid containing 1,000 meter-spaced receptors, extending 20 km from the fenceline exclusive of receptors in the fine and medium grid

**Significant Impact Analysis**

For the Significance Analysis, the net emissions increase from the project was considered in the modeling analysis. The pollutants evaluated include NO<sub>2</sub>, PM<sub>10</sub>, CO, SO<sub>2</sub>, and Ozone. These sources were assumed to operate continuously. The Ambient Ratio Method (A.R.M.), which assumes a default NO<sub>2</sub>/NO<sub>x</sub> ratio of 0.75, was used to estimate NO<sub>2</sub> emission rates for all sources. As previously stated, a significant impact for ozone is based on VOC emissions above 100 TPY. Since VOC emissions are calculated to exceed 100 TPY, a significant ozone impact results.

The following tables list the stack parameters and emission rates for each source, and the resulting impacts compared to the significant impact levels.

Source	Description	Height (m)	Temperature (k)	Velocity (m/s)	Diameter (m)
<b>New Sources</b>					
H-8601	Splitter Reboiler Heater	39.62	588.71	6.15	2.36
H-8602	HDS Feed Heater	39.62	644.26	6.07	1.45
H-8603	Stabilizer Reboiler	39.62	588.71	5.86	1.22
H-8801	H <sub>2</sub> Plant Reformer Heater	39.62	449.82	17.37	1.83
CT-11	Cooling Tower Cell 1	12.19	Ambient	23.32	4.29
CT-11	Cooling Tower Cell 2	12.19	Ambient	23.32	4.29
B-0008	Steam Boiler	45.72	422.04	3.84	2.59
FlareCF	Low Sulfur Gasoline Flare	60.96	1,273	20	1

Source	Description	Height (m)	Temperature (k)	Velocity (m/s)	Diameter (m)
<b>Associated Sources</b>					
H-0011	No. 7 HDS Charge Heater	30.48	651.48	4.09	0.91
H-0010	Sat Gas Plant Naptha Reboiler	30.48	544.26	4.40	1.43
H-0047	Gas Oil HDT Reactor Feed Heater	18.29	685.37	7.40	0.85
H-6007	No. 3 CRU Reactor Preheater	36.58	829.26	24.31	1.62
H-6012	No. 3 CRU Desulfurization Preheater	27.49	660.93	4.39	1.28
H-6013	CTU Crude Charge Process Heater	27.46	728.15	7.96	1.74
H-0023	FCCU Gas Oil Hydrotreater Heater	30.48	627.59	17.19	0.91
H-0028	No. 7 Coker Process Heater	50.60	710.37	16.93	2.29
H-0029	No. 7 Coker Process Heater	50.60	710.37	16.93	2.29
H-0057	Alky Depropanizer Heater	53.34	500.93	2.24	2.99
H-0058	Alky Depropanizer Heater	53.34	502.59	2.24	2.99
H-0059	Alky Depropanizer Heater	53.34	502.04	1.42	2.99

Source	Description	NO <sub>x</sub> (lb/hr)	PM <sub>10</sub> (lb/hr)	CO (lb/hr)	SO <sub>2</sub> (lb/hr)
<b>New Sources</b>					
H-8601	Splitter Reboiler Heater	5.22	1.11	12.27	6.07
H-8602	HDS Feed Heater	1.54	0.33	3.62	1.79
H-8603	Stabilizer Reboiler	1.16	0.25	2.72	1.34
H-8801	H <sub>2</sub> Plant Reformer Heater	3.15	0.67	7.41	0.05
CT-11	Cooling Tower Cell 1	0.00	0.04	0.00	0.00
CT-11	Cooling Tower Cell 2	0.00	0.04	0.00	0.00
B-0008	Steam Boiler	16.91	3.60	39.79	19.69
FlareCF	Low Sulfur Gasoline Flare	0.01	0.00	0.08	0.00
<b>Associated Sources</b>					
H-0011	No. 7 HDS Charge Heater	0.0003	0.00003	0.0002	0.00001
H-0010	Sat Gas Plant Naptha Reboiler	0.12	0.01	0.10	0.06
H-0047	Gas Oil HDT Reactor Feed Heater	0.14	0.01	0.09	0.0045
H-6007	No. 3 CRU Reactor Preheater	1.34	0.04	0.40	0.14
H-6012	No. 3 CRU Desulfurization Preheater	0.12	0.01	0.10	0.03
H-6013	CTU Crude Charge Process Heater	0.19	0.01	0.16	0.05
H-0023	FCCU Gas Oil Hydrotreater Heater	0.38	0.03	0.31	0.01
H-0028	No. 7 Coker Process Heater	1.13	0.03	0.34	0.01
H-0029	No. 7 Coker Process Heater	0.56	0.02	0.17	0.01
H-0057	Alky Depropanizer Heater	0.32	0.02	0.27	0.01
H-0058	Alky Depropanizer Heater	0.24	0.02	0.20	0.01
H-0059	Alky Depropanizer Heater	0.32	0.02	0.26	0.01

Pollutant	Averaging Period	SIL (ug/m <sup>3</sup> )	Modeled Impacts (ug/m <sup>3</sup> )
NO <sub>x</sub>	Annual	1	4.83
PM <sub>10</sub>	24-hour	5	3.80
	Annual	1	0.96
SO <sub>2</sub>	3-hour	25	35.80
	24-hour	5	22.28
	Annual	1	4.34
CO	1-hour	2,000	94.94
	8-hour	500	51.47
O <sub>3</sub>	*	*	*

\* No concentration has been established. Any increase of 100 tons per year of VOC requires an ambient impact analysis. Emission increases are above 100 TPY.

The modeling indicates facility emissions will result in ambient concentrations above the significance impact levels for NO<sub>x</sub>, SO<sub>2</sub>, and ozone. Therefore, full impact modeling is required for these pollutants.

**Ambient Monitoring**

The predicted maximum ground-level concentrations of pollutants by air dispersion modeling has demonstrated that the significant net emission increase from the project will result in ambient impacts below the monitoring exemption levels except for SO<sub>2</sub> and ozone. However, an existing ozone monitor is located 1.5 miles from the facility and has been determined to be acceptable as pre-construction monitoring. Additionally, an SO<sub>2</sub> monitor is located 1 mile from the facility and has been determined to be acceptable as pre-construction monitoring. These monitors have not reported any exceedances of the applicable standards. Therefore, no pre-construction nor post-construction ambient monitoring will be required. The maximum ambient impacts of the source and the monitoring exemption levels are shown in the following table.

Pollutant	Monitoring Exemption Levels		Ambient Impacts
	Averaging Time	µg/m <sup>3</sup>	µg/m <sup>3</sup>
NO <sub>2</sub>	Annual	14	4.83
SO <sub>2</sub>	24-hour	13	22.28
CO	8-hour	575	51.47
PM <sub>10</sub>	24-hour	10	3.80
Ozone	100 TPY of VOC		252 TPY VOC



### **Full Impact Analysis**

A Full Impact Analysis is required to be conducted when the net emissions increase from the proposed project results in ambient impacts above any SIL or VOC emissions exceed 100 TPY. Ambient impacts above the SILs resulted for NO<sub>2</sub> and SO<sub>2</sub> and VOC emissions exceeded 100 TPY. Therefore, a full impact analysis is required for NO<sub>2</sub>, SO<sub>2</sub>, and ozone. A full impact analysis consists of a NAAQS analysis and PSD Increment analysis.

### NAAQS Analysis

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

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

For the NO<sub>2</sub> annual averaging period, it was determined that the ROI extends for a distance of 4.33 km from the center of the Refinery. For the SO<sub>2</sub> 3-hour averaging period, it was determined that the ROI extends for a distance of 2.76 km from the center of the Refinery. For the SO<sub>2</sub> 24-hour averaging period, it was determined that the ROI extends for a distance of 4.87 km from the center of the Refinery. For the SO<sub>2</sub> annual averaging period, it was determined that the ROI extends for a distance of 3.39 km from the center of the Refinery.

In order to eliminate sources with minimal affect on ambient impacts, a screening procedure known as the "20D Rule" was applied to the sources on the emission inventory from Oklahoma. This is a screening procedure designed to reduce the number of insignificant sources. The rule is applied by multiplying the distance from the sources (in kilometers) by 20. If the result is greater than the emission rate (in tons per year), the source is eliminated. If the result is less than the emission rate, the source is included in the NAAQS analysis.

After refinery sources and all sources not eliminated by the 20D rule are modeled, the results are added to background concentrations for a determination of compliance. Acceptable background monitors for NO<sub>2</sub>, ozone, and SO<sub>2</sub> are located within the vicinity of the facility.

The most recent complete year of data was obtained from the U.S. EPA AIRSWEB database and used to determine the background concentration for NO<sub>2</sub> and SO<sub>2</sub>. The second highest concentration monitored during the most recent complete year was used for the short-term (24

hours or less) SO<sub>2</sub> averaging periods, while the highest SO<sub>2</sub> and NO<sub>2</sub> concentrations were used for the annual averaging periods.

Pollutant	Averaging Period <sup>a</sup>				
	1-hour ppm (ug/m <sup>3</sup> )	3-hour ppm (ug/m <sup>3</sup> )	8-hour ppm (ug/m <sup>3</sup> )	24-hour ppm (ug/m <sup>3</sup> )	Annual ppm (ug/m <sup>3</sup> )
NO <sub>2</sub> <sup>b</sup>	-	-	-	-	0.007 (13.2)
SO <sub>2</sub> <sup>c</sup>	0.099 (259.1)	0.046 (120.4)	-	0.02 (52.4)	0.005 (13.1)

- a. All values are monitored values from 2001
- b. Data from tribal monitor ID 400719003-1
- c. Data from SLAMS monitor ID 400710602-1

Year	1-hour Ozone Concentrations (ppm) <sup>a</sup>			
	1 <sup>st</sup> highest	2 <sup>nd</sup> highest	3 <sup>rd</sup> highest	4 <sup>th</sup> highest
1999	0.109	0.097	0.096	0.094
2000	0.101	0.097	0.096	0.093
2001	0.109	0.099	0.088	0.087

- a. Data from tribal monitor ID 400719003-1

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

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

All Refinery sources were modeled at their permit allowable or maximum design rate for the NAAQS Analysis. The maximum long-term emission rates for unpermitted units was calculated using the highest annual average heat capacity plus 10% in conjunction with AP-42 emission factors and vendor guarantees.

For short-term averaging periods the higher value of the following rates were used in conjunction with AP-42 emission factors and vendor guarantees to calculate the hourly emission rate:

- the maximum instantaneous firing rate plus 10 %,
- highest annual average heat capacity plus 10 %,
- or the permit limits

The cogeneration facility at the Refinery was installed as a joint venture between Oklahoma Gas and Electric (OG&E) and Conoco. The cogeneration facility consists of two combustion turbines and two Heat Recovery Steam Generators (HRSGs), each equipped with duct burners. The combustion turbines are owned and operated by OG&E, while the duct burners (DB-01, and DB-02) are owned and operated by Conoco. Boilers B-6 and B-7, which are owned and operated by Conoco, normally generate small quantities of steam for the Refinery; however, these boilers can be utilized at their full capacity when the combustion turbines are not operational. The emissions from the duct burners and the boilers are capped at 930.2 tpy NO<sub>x</sub> and 1,602.3 tpy SO<sub>2</sub>.

For the annual averaging periods, the worst-case stack was determined by modeling a unit emission rate through boilers and the duct burners. Emissions for the cap were allocated to the worst-case stack and then to the next worst-case, until the cap was consumed. To model short-term averaging periods, all units were conservatively assumed to operate at the maximum short-term emission rates.

The Research and Development facility is permitted separately as a synthetic minor source since it is classified under SIC code 8731. The pilot plant boilers, heaters, and flare are permitted with the flexibility to operate under an emissions cap. The emissions cap proposes to limit emissions from the pilot plant to 96 tons per year (tpy) for all criteria pollutants. The pilot plant was conservatively assumed to have all units, except the flare, operating simultaneously with the current maximum short-term design rates (lb/hr) scaled up to consume the entire cap.

The Carbon Fibers Plant will be built on land adjacent to the Refinery. The plant is permitted as a separate minor Title V source under SIC Code 3624. Since this facility is wholly owned and operated by Conoco, it was included in the model as an on-site source and modeled at its permit limits.

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

Results of initial modeling indicated exceedance of the NAAQS. However, if a facility can show that the NAAQS are not exceeded at the specific times and locations in which significant impacts are modeled for that facility, then the facility is considered in compliance with the NAAQS. Shown in the following table is the maximum concentration from all receptors in which Conoco had a significant impact. Since these are below the NAAQS as shown on the following page, the facility is in compliance.

NAAQS Analysis Results				
	Refined Model Maximum	Monitored Background	Refined + Background	NAAQS Limit
Pollutant	( $\mu\text{g}/\text{m}^3$ )	( $\mu\text{g}/\text{m}^3$ )	( $\mu\text{g}/\text{m}^3$ )	( $\mu\text{g}/\text{m}^3$ )
NO <sub>2</sub> , annual	62.31	13.2	75.51	100
SO <sub>2</sub> , 3-hour	539.00	120.4	659.40	1,300
SO <sub>2</sub> , 24-hour	288.28	52.4	340.68	365
SO <sub>2</sub> , annual	52.46	13.1	65.56	80

The Scheffe Method was used to determine compliance with the ozone NAAQS. The Scheffe Method is a screening procedure used to calculate the increase in ozone concentration due to the proposed project. A series of lookup tables, based on the Reactive Plume Model-II, is used to conservatively estimate the ozone concentration increase. Use of the Scheffe Method requires knowledge of the ratio of maximum annual non-methane volatile organic compounds (NMVOC) to NO<sub>x</sub> emissions from the proposed project. The lookup tables have been validated for NMVOC/NO<sub>x</sub> values ranging from 1 to 30. Other guidance indicates that NMVOC/NO<sub>x</sub> ratios less than 2:1 do not contribute to increased ozone formation. The project's proposed NO<sub>x</sub> emissions are 144 tpy and proposed VOC emissions are 255 tpy. Applying these rates as prescribed in the Scheffe Method, the NMVOC/NO<sub>x</sub> ratio is calculated to be 1.77. Since the NMVOC/NO<sub>x</sub> ratio is less than 2:1 the source is NO<sub>x</sub>-dominated and the NMVOC/NO<sub>x</sub> ratio is not adequate for ozone formation. Therefore, based on existing monitoring the facility is estimated to comply with the ozone NAAQS.

PSD Increment Analysis

The PSD Increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging times) and is the ambient concentration existing at the time that the first complete PSD permit is submitted for that area. An emission source removed from the area is considered as a reduction in consumed increment.

The baseline dates were determined to be February 20, 1992, and August 25, 1982, for NO<sub>x</sub> and SO<sub>2</sub>, respectively. The following table lists the increment for each pollutant requiring full PSD review.

Pollutant	Averaging Period	Increment
NO <sub>2</sub>	Annual	25 $\mu\text{g}/\text{m}^3$
SO <sub>2</sub>	3-hour	512 $\mu\text{g}/\text{m}^3$
	24-hour	91 $\mu\text{g}/\text{m}^3$
	Annual	20 $\mu\text{g}/\text{m}^3$

The first step in evaluating increment consumption is to develop a list of sources within the ROI plus 50 km. These sources were then screened using the previously described 20-D rule. Those

sources not screened out were then reviewed to determine dates of installation. Those units installed after the baseline dates were included in the modeling and were modeled at their full potentials for the PSD Increment Analysis. The full potential used was the permitted emission limit. Source parameters not included in the permits or permit memoranda were obtained from the 2000 EI. Continental Carbon, OMPA, and Jupiter, as well as the OG&E combustion turbines at the Refinery, have units that were installed after the baseline dates. Following, is a description of the emission rates used for all refinery sources. For all sources with emissions listed as  $\text{NO}_x$ , the A.R.M. was used to calculate the  $\text{NO}_2$  emissions.

### Refinery Sources

All Refinery sources installed since the baseline date of February 20, 1992, for  $\text{NO}_2$  and August 25, 1982, for  $\text{SO}_2$  were modeled at their full potentials. The full potential is either the permitted emission limits or for those units that have not been permitted, the maximum design potential of the unit. All units installed prior to the baseline dates were adjusted to account for their current increment consumption. The sources' past actual emissions (i.e., emissions prior to the baseline date) were subtracted from current potentials to obtain the annual emission rate. All units removed from operation since the baseline dates were modeled as negative emission rates based on their actual emissions prior to the baseline date. Short-term emission rates were only adjusted for increment consumption if additional controls were installed since the baseline date.

#### 1. Process Heaters

The maximum potential emissions for unpermitted sources were calculated using the higher of the highest annual average heat capacity plus 10% in conjunction with the AP-42 emission factors and vendor guarantees to calculate the potential annual emissions.

For short-term averaging periods the higher value of the following rates were used in conjunction with AP-42 emission factors and vendor guarantees to calculate the hourly emission rate.

- the maximum instantaneous firing rate plus 10 %,
- highest annual average heat capacity plus 10 %,
- or the permit limits

The stack height for H-6007 increased from 57 feet to 120 feet in 1992. All other stack parameters remained the same. Therefore, based on EPA guidance both the pre-baseline conditions and the current conditions must be input in the model. The baseline case stack parameters are input in the model with the corresponding emission rate as a negative, and the current stack parameters are input in the model with the current potentials as a positive value. This procedure calculates, for each receptor and averaging period time, the difference between the baseline concentration and the current concentration.

To quantify the PSD Increment consumption for NO<sub>2</sub>, pre-baseline actual emissions (Appendix D) were subtracted from the current potentials. These annual emission rates were then converted to an hourly emission rate assuming continuous operation for annual averaging periods. The 1991 emissions were adjusted by multiplying the actual emissions by a ratio of the current AP-42 emission factor to the historical AP-42 emission factor in effect in 1991.

The 1981 actual emissions were calculated from a ratio of 1981 refinery production to 1991 refinery production/emissions to quantify the PSD Increment consumption for the SO<sub>2</sub> long-term annual averaging period. These scaled emissions were subtracted from the current potentials to obtain the actual long-term emissions change since the baseline date.

For the short-term SO<sub>2</sub> PSD Increment emission rate, units which have become subject to Subpart J since the baseline date and the (Sulfur Recovery Unit) SRU tail gas heaters (H-5004 and H-5003) were assumed to have a change in short-term emissions. Those units that have become subject to Subpart J were adjusted to 1981 short-term emissions and subtracted from the current potential short-term emission rate. They were adjusted by converting the current annual emissions to a short-term emission rate and multiplying by the ratio of the concentration of sulfur prior to Subpart J, based on the permit memorandum for 91-043-O (M-4), to Subpart J requirements.

All other units are modeled at the current short-term potential emission rate.

## 2. Refinery Cogeneration Plant

The cogeneration facility at the Refinery was installed as a joint venture between Oklahoma Gas and Electric (OG&E) and Conoco. The cogeneration facility consists of two combustion turbines and two Heat Recovery Steam Generators (HRSGs), each equipped with duct burners. The combustion turbines are owned and operated by OG&E, while the duct burners (DB-01, and DB-02) are owned and operated by Conoco. Boilers B-6 and B-7, which are owned and operated by Conoco, normally generate small quantities of steam for the Refinery; however, these boilers can be utilized at their full capacity when the combustion turbines are not operational. The first year of operation for the duct burners was 1991; however it was not representative of current operations. Therefore, the emissions reported in the 2000 EI, which are more representative, were scaled to pre-baseline values by a ratio of the amount of barrels refined in 2000 to the amount of barrels refined in 1991.

The sum of these emissions was then subtracted from the cap to determine the total NO<sub>2</sub> PSD increment consuming emissions from the cogeneration facility. The incremental increase was then conservatively split amongst the units by maximizing the short-term emission rate for the worst case stack (DB-01). The cap was then allocated from worst case to best case stack. The incremental increase was consumed by DB-01.

The duct burners for the cogeneration facility were installed after the SO<sub>2</sub> baseline date; therefore, they were modeled at full potentials for both short-term and long-term averaging periods. The boilers were installed prior to the baseline date; therefore, the difference in potential emissions to actual emissions prior to the baseline date was used.

To determine the pre-baseline emissions, the 1989-1990 combined emissions from boilers B-1, B-2, B-4, B-5, B-6, and B-7 were scaled to 1982 emissions by multiplying the emissions by the ratio of the 1982 refinery throughput to the average 1989-1990 refinery throughput.

These emissions were then combined and subtracted from the remainder of the cap.

These emissions were then routed through the best case stack for Conoco, since the emissions are a decrease. Boiler B-7 was determined to be the best case stack for the long-term averaging period.

For SO<sub>2</sub> short-term emissions, the average 1989-1990 emissions for boilers B-1, B-2, B-4, B-5, B-6, and B-7 were combined and subtracted from the current potentials. Those emissions were then routed through B-7.

### 3. Refinery Research and Development Plant

The Research and Development facility is permitted separately as a synthetic minor source since it is classified under SIC code 8731. The facility was originally permitted in 1981 and a modification to Permit No. (81-105-O) was submitted by Conoco to the DEQ on June 11, 2001. The facility was conservatively assumed to be an increment consumer for both NO<sub>2</sub> and SO<sub>2</sub> and no adjustment was made for its emissions prior to the baseline dates.

The pilot plant boilers, heaters, and flare are permitted with the flexibility to operate under an emissions cap. The emissions cap proposes to limit emissions from the pilot plant to 96 tpy for all criteria pollutants. The pilot plant was conservatively modeled assuming that all units, except the flare, operate simultaneously at the maximum short-term design rates (lb/hr), scaled up to consume the entire cap. Since this facility is wholly owned and operated by Conoco, it was included in the model as an on-site source.

### 4. Refinery Carbon Fibers Plant

The Carbon Fibers Plant is being built on land adjacent to the Refinery. The plant is permitted as a separate minor Title V source under SIC Code 3624. Since this facility is currently under construction, it is an increment consumer and is modeled at its permit limits. Since this facility is wholly owned and operated by Conoco, it was included in the model as an on-site source.

5. Refinery Flares

Emissions from flares were assumed to only come from the flare pilot fuel, since the flares are only used in upset conditions. Some of the flares were installed prior to the baseline dates for both NO<sub>2</sub> and SO<sub>2</sub>, but they were conservatively included in the modeled as increment consumers at their full potentials. These units were not adjusted for their emission potential before the baseline dates due to the insignificant level of emissions.

Increment Modeling Results

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

Pollutant	Averaging Period	Increment	Maximum Modeled NO <sub>2</sub> Increase
NO <sub>2</sub>	Annual	25 ug/m <sup>3</sup>	13.06 ug/m <sup>3</sup>
SO <sub>2</sub>	3-hour	512 ug/m <sup>3</sup>	113.56 ug/m <sup>3</sup>
	24-hour	91 ug/m <sup>3</sup>	87.37 ug/m <sup>3</sup>
	Annual	20 ug/m <sup>3</sup>	-0.01 ug/m <sup>3</sup>

Additional Impacts Analysis

**Growth Impacts**

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

**Soils and Vegetation**

The following discussion will review the project’s potential to impact its agricultural surroundings based on the project’s allowable emission rates and resulting ground level concentrations of NO<sub>x</sub>. NO<sub>x</sub> was selected for review since it has been shown to be capable of causing damage to vegetation at elevated ambient concentrations.

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



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

NO<sub>2</sub> may affect vegetation either by direct contact of NO<sub>2</sub> with the leaf surface or by solution in water drops, becoming nitric acid. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. The maximum predicted NO<sub>2</sub> pollutant concentration from the proposed project is below the secondary NAAQS. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil and vegetation is anticipated due to the proposed low Sulfur Gasoline project.

VOCs are regulated by the U.S. EPA as precursors to tropospheric ozone. Elevated ground-level ozone concentrations can damage plant life and reduce crop production. VOCs interfere with the ability of plants to produce and store food, making them more susceptible to disease, insects, other pollutants, and harsh weather. As discussed in the separate dispersion modeling report, no significant impact on soil and vegetation due to VOC emissions is anticipated due to the proposed Low Sulfur Gasoline project.

At the levels of CO that occur in urban air, there are no detrimental effects on materials or plants, however human health may be adversely affected at such levels. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. The maximum predicted CO pollutant concentration from the proposed project are expected to be below the secondary NAAQS. As discussed in the separate dispersion modeling report, no significant adverse impact on soil and vegetation due to CO emissions is anticipated due to the proposed Low Sulfur Gasoline project.

### **Visibility Impairment**

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

### **Class I Area Impact Analysis**

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

Under the PSD provisions, Congress established a land classification scheme for those areas of the country with air quality better than the NAAQS. Class I allows very little deterioration of air

quality, Class II allows moderate deterioration, and Class III allows more deterioration but in all cases, the pollution concentrations should not violate any of the NAAQS. Certain existing areas were designated as mandatory Class I, which precludes redesignation to a less restrictive class, in order to acknowledge the value of maintaining these areas in relatively pristine condition. These Class I areas include:

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

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

## SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES

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

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

OAC 252:100-4 (New Source Performance Standards) [Applicable]  
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on July 1, 2001, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Ca, Subpart Cb, Subpart Cc, Subpart Cd, Subpart Ce, Subpart AAA, and Appendix G. NSPS regulations are covered in the "Federal Regulations" section.

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

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

OAC 252:100-8 (Permits for Part 70 Sources)

[Applicable]

Part 3 summarizes permit application fees for Part 70 source permits. Conoco has submitted the required permit modification fee of \$1,500.

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

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule
- 0.6 TPY of any one Category A toxic substance
- 1.2 TPY of any one Category B toxic substance
- 6.0 TPY of any one Category C toxic substance

This proposed project is considered a physical change that is considered a significant modification of a Part 70 permit, therefore, a construction permit is required. After construction, the operating permit for this modification will be incorporated into the facility’s initial Part 70 permit, yet to be issued.

Part 7 summarizes Prevention of Significant Deterioration (PSD) requirements. See the “Federal Regulations” section for a discussion of PSD regulations.

OAC 252:100-9 (Excess Emission Reporting Requirements)

[Applicable]

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

OAC 252:100-13 (Prohibition of Open Burning)

[Applicable]

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

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

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

OAC 252:100-29 (Fugitive Dust) [Applicable]  
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. This project does not involve any new sources with significant particulate matter emissions.

OAC 252:100-31 (Sulfur Compounds) [Applicable]  
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). This part prohibits discharge of SO<sub>2</sub> from new gas-fired fuel-burning equipment in excess of 0.2 lb/MMBtu three-hour average. Four of the proposed sources are subject to NSPS Subpart J, which limits the hydrogen sulfide content and result in emissions of 0.0407 lb/MMBtu. The remaining sources are limited to pipeline quality natural gas with emissions of 0.0006 lb/MMBtu. Therefore, the sources will be in compliance.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]  
Subchapter 33 affects discharge of NO<sub>x</sub> from new gas-fired fuel-burning equipment with a rated heat input of 50 MMBtuh or more. NO<sub>x</sub> is limited to 0.2 lb/MMbtu two hour average, expressed as NO<sub>2</sub>. Process heaters H-8601 and H-8801 and boiler B-008 will all be limited to maximum NO<sub>x</sub> emissions of 0.035 lb/MMBtu. This emission rate is in compliance with this subchapter. Process heaters H-8602 and H-8603 are below the heat input threshold and are not subject to this subchapter.

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]  
The project does not involve the installation of any of the following equipment: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]

Part 3 requires storage tanks constructed after 12/28/74 with a capacity of 40,000 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped internal/external floating roofs or vapor recovery devices. All six storage tanks associated with this project are subject to NSPS Subpart Kb and are, therefore, exempt from this part.

Part 7 also requires fuel-burning and refuse-burning equipment to be operated to minimize emissions of VOC. All the combustion units are subject to this requirement.

Part 7 also requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands and rotating pumps and compressors handling VOCs to be equipped with mechanical seals. The new pumps and compressors will be subject to this requirement.

OAC 252:100-41 (Hazardous and Toxic Air Contaminants) [Applicable]

Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on July 1, 2001, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radio nuclides. General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, XXX, CCCC, and GGGG are hereby adopted by reference as they exist on July 1, 2001. These standards apply to both existing and new sources of HAPs. NESHAP Regulations are covered in the "Federal Regulations" section.

Part 5 is a state-only requirement governing toxic air contaminants. New sources (constructed after March 9, 1987) emitting any category "A" pollutant above de minimis levels must perform a BACT analysis, and if necessary, install BACT. All sources are required to demonstrate that emissions of any toxic air contaminant, which exceeds the de minimis level, do not cause or contribute to a violation of the MAAC. This subchapter provides an exemption for all HAPs which are regulated under 40 CFR Part 63. All other HAPs and/or toxics must be shown to be in compliance. Compliance with this subchapter is demonstrated in Section III, "Emissions."

OAC 252:100-43 (Sampling and Testing Methods) [Applicable]

All required testing must be conducted by methods approved by the Executive Director under the direction of qualified personnel. All required tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by Air Quality.

OAC 252:100-45 (Monitoring of Emissions) [Applicable]

Records and reports as Air Quality shall prescribe on air contaminants or fuel shall be recorded, compiled, and submitted as specified in the permit.

**SECTION VIII. FEDERAL REGULATIONS**

PSD, 40 CFR Part 52

[Applicable]

PSD applies to this project. PSD review was completed in Section VI.

NSPS, 40 CFR Part 60

[Subparts A, Db, J, Kb, GGG, and QQQ are Applicable]

Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected sources. Within 30 days after starting construction of the affected sources, Conoco must notify DEQ that construction has commenced. A notification of the actual date of initial startup of any affected source will be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup of the source. Conoco 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 comply with the notification requirements set forth in Subpart A.

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a design capacity greater than 100 MMBTUH heat input and which commenced construction or modification after June 19, 1984. The 483.2 MMBTUH gas-fired boiler is an affected unit. However, since the unit is also subject to Subpart J it is only subject to the particulate matter and nitrogen oxides standards. The particulate matter standard is not applicable since the unit is limited to gaseous fuels. The nitrogen oxide limit for natural gas is 0.10 lb/MMBtu for low heat release and 0.20 lb/MMBtu high heat release. This subpart also includes testing, reporting, and recordkeeping which will be a requirement of the permit. H-8601 also has a design capacity above 100 MMBTUH, however, it is defined as a process heater and is, therefore, not subject.

Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects industrial-commercial-institutional steam generating units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989. Heaters H-8602, 8603, and 8801 have design capacities between 10 and 100 MMBTUH, however, these heaters are defined as process heaters and are, therefore, not subject.

Subpart J, Petroleum Refineries. This subpart provides a limit of 0.10 gr/dscf for H<sub>2</sub>S content in fuel gas burned in any fuel gas combustion device. A continuous monitoring device to measure either SO<sub>2</sub> emission concentration or H<sub>2</sub>S concentration in the fuel gas must also be installed. Subpart J also includes testing, reporting, and recordkeeping requirements. Three of the four heaters and the boiler to be installed as part of this project will be subject to Subpart J and will comply with the H<sub>2</sub>S requirements of Subpart J. The hydrogen plant reformer heater (EU ID H-8801) will combust only natural gas and PSA offgas; therefore, it is not subject to this subpart. NSPS Subpart J compliance for the new Low Sulfur Gasoline flare will be in accordance with 40 CFR §60.11(d) in lieu of the requirements of 40 CFR §60.104(a)(1) and as outlined in the

options provided in Civil Action No. H-01-4430 including the procedures set forth in Paragraphs 183 through 188 of Civil Action No. H-01-4430. A flare gas recovery system will be installed on this new flare to comply with NSPS Subpart J 40 CFR §60.11(d).

Subpart Kb, Volatile Organic Liquids Storage Vessels. This subpart affects VOL storage vessels (including petroleum liquids storage vessels) for which construction, reconstruction, or modification commenced after July 23, 1984, and which have a capacity of 10,567 gallons (40 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. The tanks will be constructed with internal floating roofs in compliance with this subpart. Monitoring, reporting, and recordkeeping will be a requirement of the permit.

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

Subpart QQQ. This subpart affects refinery wastewater systems for which construction, reconstruction, or modification commenced after May 4, 1987. This project will involve physical changes to individual drain systems in the form of new process drains and junction boxes. The permit will require compliance with this subpart by ensuring that new drains installed as part of this project are equipped with water seal controls and that the applicant comply with the monitoring, testing, recordkeeping, and reporting requirements of this standard. The stormwater collection system will be segregated from the process sewer system and, therefore, is not subject to the control requirements of this subpart. The new wastewater stream system is required to only comply with 40 CFR Part 63, Subpart CC.

NESHAP, 40 CFR Part 61

[ Subpart FF is Applicable]

Subpart FF, Benzene Waste Operations. This subpart applies to waste streams at chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries that have benzene-containing hazardous waste treatment, storage, and disposal facilities. The benzene concentration for each affected individual drain system can be greater than 10 ppmw. Therefore,

in accordance with 40 CFR 61.342(c)(2), the control requirements in this subpart are applicable to this proposed project and the new process sewer system (drains and junction boxes) will be controlled in accordance with 40 CFR 61.346(b). The stormwater collection system will be segregated from the process sewer system and, therefore, is not subject to the control requirements of this subpart.

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

NESHAP, 40 CFR Part 63

[Applicable]

Subpart CC, National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries. This subpart affects petroleum refining process units and related emission points located at a plant site that is a major source as defined in section 112(a) of the Clean Air Act and emits or contacts one or more of the hazardous air pollutants listed in table 1 of this subpart. The various emission units includes:

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

This project involves the construction of storage vessels, wastewater streams, and equipment leak components. The storage tanks will comply with 40 CFR Part 60 Subpart Kb, therefore, they will be in compliance with this subpart. The new wastewater stream system is only required to comply with this subpart. Waste streams in benzene service will comply with 40 CFR 61 Subpart FF, therefore, they will be in compliance with this subpart. The equipment leak components are only required to comply with this subpart.

CAM, 40 CFR Part 64

[Not Applicable to this Project]

Compliance Assurance Monitoring (CAM) as published in the Federal Register on October 22, 1997, applies to any pollutant-specific emission unit at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

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



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

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]

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

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]

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

## SECTION IX. 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 facility 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 "Notice of Filing a Tier II Application" in the *Ponca City News*, a daily newspaper in Kay County, on July 13, 2001. The notice stated that the application was available for public review at the Ponca City Library or at the AQD office. A draft of this permit was also made available for public review for a period of 30 days as stated in another newspaper announcement. The applicant published the "Notice of Draft Permit and Public Meeting" in the *Ponca City News*, a daily newspaper in Kay County, on May 21, 2002. The notice stated that the draft permit was available for public review at the Ponca City Library or at the AQD office and that a public meeting would be held on June 20, 2002. This facility is also located within 50 miles of the Oklahoma border with Kansas. The state of Kansas was notified of the draft permit. The public meeting was held as scheduled. No comments were received from the public, EPA, or the state of Kansas.

Information on all permit actions is available for review on the Air Quality section of the DEQ web page at <http://www.deq.state.ok.us>.

**Fees Paid**

Construction permit fee of \$1500. \$2000 submitted, \$500 to be refunded.

**SECTION X. SUMMARY**

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

**PERMIT TO CONSTRUCT  
AIR POLLUTION CONTROL FACILITY  
SPECIFIC CONDITIONS**

**Conoco, Inc.  
Ponca City Refinery  
Low Sulfur Gasoline Project**

**Permit No. 2001-194-C (PSD)**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on August 7, 2001. The Evaluation Memorandum dated July 1, 2002, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and emissions limitations

A. Heaters and Reboilers

<b>EU</b>	<b>Maximum Firing Rate, MMBTU/HR</b>	<b>Pollutant</b>	<b>Emissions</b>	
			<b>lb/hr</b>	<b>TPY</b>
H-8601, Splitter Reboiler	149	NO <sub>x</sub>	5.22	22.84
		SO <sub>2</sub>	6.06	26.56
		CO	12.28	53.78
		VOC	0.80	3.52
		PM <sub>10</sub>	1.12	4.89
H-8602, Hydrodesulfurization Heater	44	NO <sub>x</sub>	1.54	6.75
		SO <sub>2</sub>	1.79	7.84
		CO	3.63	15.88
		VOC	0.24	1.04
		PM <sub>10</sub>	0.33	1.45
H-8603, Stabilizer Reboiler	33	NO <sub>x</sub>	1.16	5.06
		SO <sub>2</sub>	1.34	5.88
		CO	2.72	11.91
		VOC	0.18	0.78
		PM <sub>10</sub>	0.25	1.08
H-8801, H <sub>2</sub> Plant Reformer	90	NO <sub>x</sub>	3.15	13.80
		SO <sub>2</sub>	0.05	0.24
		CO	7.42	32.48
		VOC	0.49	2.13
		PM <sub>10</sub>	0.68	2.96

- i. H-8601, H-8602, and H-8603 shall combust only pipeline grade natural gas or refinery fuel gas with a maximum H<sub>2</sub>S concentration of 0.10 gr/dscf (160 ppmv).
- ii. H-8801 shall be limited to pipeline grade natural gas and PSA offgas only.
- iii. Total fired duty shall be limited as indicated. Compliance shall be determined daily and be based on a 365 day rolling average.
- iv. Each of the sources shall be constructed with Ultra Low NO<sub>x</sub> Burners (ULNB) with NO<sub>x</sub> emissions limited to 0.035 lb/mmbtu.
- v. Each of the sources shall be operated using good combustion practices to comply with the listed emission rates.
- vi. H-8601, H-8602, and H-8603 are subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements, including but not limited to;
  - a. §60.104 Standards for sulfur oxides
  - b. §60.105 Monitoring of emissions and operations
  - c. §60.106 Test methods and procedures
  - d. §60.107 Reporting and recordkeeping requirements
  - e. §60.108 Performance test and compliance provisions
- vii. Within 60 days of achieving maximum firing rate from the heaters/reboilers, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing and furnish a written report to Air Quality documenting compliance with emissions limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR Part 60:
  - Method 1: Sample and Velocity Traverses for Stationary Sources.
  - Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
  - Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
  - Method 4: Determination of Moisture in Stack Gases.
  - Method 7E: Determination of Nitrogen Oxide Emissions from Stationary Sources.
  - Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources.

NO<sub>x</sub> and CO testing shall be conducted while the new units are operating within 10% of the maximum firing rates.

**B. Boiler**

EU	Maximum Firing Rate, MMBTU/HR	Pollutant	Emissions	
			Lb/hr	TPY
B-0008, Boiler	483.2	NO <sub>x</sub>	16.91	74.07
		SO <sub>2</sub>	19.67	86.14
		CO	39.82	174.39
		VOC	2.61	11.43
		PM <sub>10</sub>	3.62	15.87

- i. B-0008 shall combust only pipeline grade natural gas or refinery fuel gas with a maximum H<sub>2</sub>S concentration of 0.10 gr/dscf (160 ppmv).
- ii. Total fired duty shall be limited as indicated. Compliance shall be determined daily and be based on a 365 day rolling average.
- iii. The boiler shall be constructed with Ultra Low NO<sub>x</sub> Burners (ULNB) with NO<sub>x</sub> emissions limited to 0.035 lb/mmbtu.
- iv. The boiler shall be operated using good combustion practices to comply with the listed emission rates.
- v. B-0008 is subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements, including but not limited to.
  - a. §60.104 Standards for sulfur oxides
  - b. §60.105 Monitoring of emissions and operations
  - c. §60.106 Test methods and procedures
  - d. §60.107 Reporting and recordkeeping requirements
  - e. §60.108 Performance test and compliance provisions
- vi. Within 60 days of achieving maximum firing rate from the heaters/reboilers, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing and furnish a written report to Air Quality documenting compliance with emissions limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR Part 60:
  - Method 1: Sample and Velocity Traverses for Stationary Sources.
  - Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
  - Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.
  - Method 4: Determination of Moisture in Stack Gases.
  - Method 7E: Determination of Nitrogen Oxide Emissions from Stationary Sources.
  - Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources.

NO<sub>x</sub> and CO testing shall be conducted while the new units are operating within 10% of the maximum firing rates.

C. Tanks

Parameter	EU	
	T-145, T-146, T-157, and T-161	T-121 and T-122
Contents	Hydrocarbons	Hydrocarbons
Capacity, barrels	80,000	200,000
Vapor Pressure, psia	11.0	11.0
Annual Throughput per Tank, gallons	5,241,600	8,400,000
Design	Internal Floating Roof	Internal Floating Roof

- i. The listed tanks shall only store hydrocarbon liquids with vapor pressures less than the maximum indicated and be designed with internal floating roofs or equivalent.
- ii. Total annual throughput shall be limited as indicated. Compliance shall be determined monthly and be based on 12-month rolling totals.
- iii. The tanks are subject to NSPS 40 C.F.R. Part 60, Subpart Kb and shall comply with all applicable standards including but not limited to and except as provided in §63.640 (n)(8);
  - a. The owner or operator shall visually inspect the floating roof, the primary seal, the secondary seal (if present), gaskets, slotted membranes (if present), and sleeve seals (if present) each time the storage vessel is emptied and degassed. If the floating roof has defects, the seals have holes, tears, or other openings in the seal or seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10% open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exists before refilling the storage vessel with volatile organic liquid (VOL). In no event shall inspections conducted in accordance with this provision occur at intervals greater than five (5) years.
  - b. The owner or operator shall notify the division in writing at least 30 days prior to filling or refilling of this storage vessel for which inspection is required by 40 CFR 60.113b(a)(5) to afford AQD an opportunity to have an observer present. If the inspection is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the AQD at least seven days prior to refilling the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent so that it is received by the AQD at least seven days prior to refilling.

- c. The owner or operator of these storage vessels shall keep records and furnish reports as required by 40 CFR 60.115b(a). Copies of these reports and records shall be kept for at least five years following the date on which they were made.
- iv. The owner or operator shall maintain a record of the volatile organic liquid stored, the period of storage and the maximum true vapor pressure of that VOL during the respective storage period for each tank. Copies of these records shall be retained on location for at least five years after the dates of recording. Available data on the storage temperature may be used to determine the maximum true vapor pressure. For crude oil or refined petroleum products, available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517.
- v. NESHAP 40 CFR Part 63 applies to the tanks. The permittee shall comply with the applicable sections of Subpart CC.
  - a. §63.640 Applicability
  - b. §63.646 Storage Vessel Provisions
  - c. §63.654 Reporting and Recordkeeping

**D. Fugitive Components**

<b>EU</b>	<b>Estimated Number of Components*</b>
<b>SHU, Splitter, HDS</b>	
Light Liquid Valves	1108
Flanges	2875
Light Liquid Pumps	10
Gas Compressors	1
Gas Relief Valves to Flare	15
Sample Stations	5
Drains	50
Controlled Junction Boxes	10
<b>Isom Unit</b>	
Light Liquid Valves	440
Flanges	1099
Light Liquid Pumps	8
Gas Relief Valves to Atmosphere	12
Gas Relief Valves to Flare	15
Sample Stations	5
Drains	50
Controlled Junction Boxes	10

EU	Estimated Number of Components*
<b>Hydrogen Plant</b>	
Gas Valves	15
Light Liquid Valves	146
Flanges	450
Light Liquid Pumps	2
Gas Compressors	2
Gas Relief Valves to Atmosphere	11
Gas Relief Valves to Flare	15
Sample Stations	8
Drains	50
Controlled Junction Boxes	20

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

- i. NESHAP, 40 CFR Part 63, Subpart CC, applies to the following affected equipment: each compressor, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. The permittee shall comply with the applicable sections for each affected component.
  - a. §63.642 General Standards
  - b. §63.648 Equipment Leak Standards
  - c. §63.654 Reporting and Recordkeeping Requirements
- ii. Equipment determined not to be in HAP service (<5% by weight HAP) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG.
- iii. NESHAP, 40 CFR 61, Subpart FF applies to the process sewer system in benzene service. The permittee shall comply with all applicable standards including but not limited to;
  - a. §61.346: Standards, Individual drain systems
  - b. §61.349: Standards, Closed vent systems and control devices
  - c. §61.350: Standards, Delay of repair
  - d. §61.353: Alternative means of emission limitation
  - e. §61.354: Monitoring of operations
  - f. §61.355: Test methods, procedures, and compliance provisions
  - g. §61.356: Record keeping requirements
  - h. §61.357: Reporting requirements



**E. Cooling Tower**

<b>EU</b>	<b>VOC Emissions</b>	
	<b>lb/hr</b>	<b>TPY</b>
<b>Cooling Tower</b>		
CT-11	0.42*	1.84*

\* estimates only, compliance is based on the following listed requirements

- i. The Cooling Tower shall be constructed with drift eliminators.
- ii. The permittee shall monitor the water flow through the cooling tower.
- iii. At least once monthly, the permittee shall determine the VOC concentration of the water.

**F. Flare**

<b>EU</b>	<b>Maximum Firing Rate, MMBTU/HR</b>
Flare CF	0.2

- i. The flare shall be designed for smokeless operation and be operated using good combustion practices.
- ii. The flare pilot shall be fueled with pipeline grade natural gas.
- iii. The Low Sulfur Gasoline Flare is subject to federal New Source Performance Standard (NSPS), Subpart J. Compliance will be in accordance with 40 CFR §60.11(d) in lieu of the requirements of 40 CFR § 60.104(a)(1) and as outlined in the options provided in Civil Action No. H-01-4430 including the procedures set forth in Paragraphs 183 through 188 of Civil Action No. H-01-4430. A flare gas recovery system will be installed on this new flare to comply with NSPS Subpart J 40 CFR § 60.11(d).

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

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

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

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

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

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

6. No later than 30 days after each anniversary date of the issuance of this permit, the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit. The following specific information is required to be included:

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

- a. Annual average fired duty for each unit in S.C. 1 for the 12-month period preceding the anniversary date.

Conoco, Inc.  
Attn: Jim Phelan  
P.O. Box 1267  
Ponca City, OK 74602-1267

Re: Permit Number 2001-194-C (PSD)  
Gasoline Clean Fuels Project

Dear Mr. Phelan:

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

Thank you for your cooperation in this matter. If we may be of further service, please contact me at (405) 702-4203.

Sincerely,

Phillip Fielder, P.E.  
New Source Permits Unit  
AIR QUALITY DIVISION

cc: Kay County



# PERMIT

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

Date \_\_\_\_\_ Permit No. 2001-194-C (PSD)  
Conoco, Inc.,

having complied with the requirements of the law, is hereby granted permission to construct the specified equipment for the Gasoline Clean Fuels Project in Ponca City, Kay County, OK,

subject to the following conditions, attached:

Standard Conditions dated October 17, 2001

Specific Conditions

\_\_\_\_\_  
Director, Air Quality Division

DEQ Form 885  
Revised 7/93