

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

MEMORANDUM

May 23, 2008

TO: Phillip Fielder, P.E., Permits & Engineering Group Manager, Air Quality

THROUGH: Kendal Stegmann, Senior Environmental Manager, Compliance and Enforcement

THROUGH: Jian Yue, P.E., Engineering Section

THROUGH: David Schutz, P.E., New Source Permits Section

THROUGH: Peer Review

FROM: Phillip Martin, P.E., Engineering Section

SUBJECT: Evaluation of Permit Application No. **98-014-C (M-14) PSD**
Sunoco, Inc. (R&M) (**Sunoco**)
Tulsa Refinery
Sunoco Diesel Upgrade Project
1700 South Union
Tulsa, Tulsa County, OK
Latitude 36.138, Longitude 96.009 W

SECTION I. INTRODUCTION

Sunoco Incorporated (Sunoco) owns and operates a petroleum refinery (SIC 2911, NAICS 32411) in Tulsa, Oklahoma (the Tulsa Refinery). The facility is currently operating under Permit No. 98-014-TV issued on May 30, 2006 and modifications 98-014-TV (M-8), 98-014-TV (M-9), and 98-014-TV (M-10). The refinery is a Title V major source and is located in an area designated as attainment for all criteria air pollutants. The refinery is an existing major source for the Federal Prevention of Significant Deterioration (PSD) program and a Maximum Achievable Control Technology (MACT) source category regulated under 40 CFR Part 63, Subpart CC (MACT I) and Subpart UUU (MACT II).

Sunoco is proposing to construct a diesel hydrotreating unit (DHT) for the production of ultra low sulfur diesel (ULSD). Sunoco expects to start construction upon receipt of this permit and commission the project by first quarter of 2010. The objective of the project is to provide facilities to produce ULSD at the Tulsa Refinery. This project will construct a diesel hydrotreater, amine fuel gas contactor and amine regenerator, Claus sulfur recovery unit with associated tail gas treater and incinerator, and a sour water stripper. Each of these processes is an integral part of the Diesel Upgrade Project. The Diesel Upgrade Project will result in a net emissions increase for NO_x that is greater than the PSD Significant Emission Rate (SER) for

NO_x. Therefore, the project is subject to PSD review. No other regulated air pollutant is emitted in significant amounts to require PSD review.

The ULSD project is being installed to meet U.S. EPA standards for sulfur concentration in highway diesel fuel. On January 21, 2001, the U.S. EPA published the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements rule that required refiners to lower the sulfur content in diesel from 500 parts per million (ppmw) to 15 ppmw by June 1, 2006. The refinery currently only produces off-road diesel with high sulfur content.

SECTION II. PROJECT SUMMARY

Sunoco is proposing to construct a DHT for the production of ULSD. The refinery does not currently hydrotreat diesel. This project will construct a new 32,000-barrel per day (bpd), 1,200-psig hydroprocessing facility to desulfurize diesel boiling range distillate streams to ULSD standards. The design ULSD sulfur specification is 15 ppmw.

The hydrotreated diesel from the DHT unit will be processed through a new diesel stripper column where hydrogen sulfide (H₂S) gas and light hydrocarbons (HCs) will be stripped from the diesel. The ULSD recovered from the column bottom will be directed to product tankage for shipping.

The stripper offgas will be directed to a new Amine Treatment Unit (ATU) downstream of the stripper where the sour offgas will be sweetened to NSPS-grade refinery fuel gas (RFG). The sour gas will contain H₂S and will be directed to a new sulfur recovery unit (SRU) where the H₂S gas will be reduced to water and elemental sulfur. The offgas from the SRU will be routed to a tail-gas treatment unit (TGTU) for further recovery of sour gases. The sour gases from the TGTU will be circulated back into the SRU for further processing. The TGTU exhaust will be directed to a gas-fired incinerator for final destruction.

Two new combustion sources and existing boilers will be utilized to provide steam and heat requirements for the new process line. The sweetened RFG recovered from the ATU will be used as fuel in the new combustion units and several other existing combustion sources.

The majority of the DHT feedstocks will come from different intermediate cuts from the existing refinery. Additional feed material may be purchased from other refineries. The purchased feedstocks will be received by truck, rail, or pipeline. The overall DHT throughput will impact some of the downstream processing units, including storage and transportation operations at the refinery. Two new storage tanks will be constructed as part of the Diesel Upgrade Project, one to store amine and the second for sour water storage.

Sunoco is also subject to a Consent Decree entered in the U.S. District Court for the Eastern District of Pennsylvania on June 16, 2005, which requires the refinery to undertake certain emission reduction actions.

PSD Applicability

Emissions decreases resulting from compliance with the Consent Decree are not creditable for PSD netting purposes, except for 250 TPY of SO₂ in total for all of the Sunoco refineries as specified in the Consent Decree. The issuance of this permit will retire the SO₂ Consent Decree credits in total and they may not be used at any other Sunoco refinery.

As summarized in Table II-1, emissions attributable to projects not related to the Consent Decree that are included in this permit exceed PSD significance levels for NO_x. These projects, when combined with other planned and completed projects in the contemporaneous netting period, show that only NO_x is above the PSD SER. Therefore, the proposed changes are subject to PSD permitting requirements for NO_x only. The PSD review for this permit also requires an air quality analysis to estimate the ambient impacts of emissions from the project (OAC 252:100-8-35). A full PSD analysis including an air quality analysis is presented in Section V of this memorandum.

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

Pollutant	Emission Rate, TPY	PSD Significant Emission Rate, TPY	Subject to PSD Review?
CO	63.01	100	No
PM ₁₀	13.45	15	No
NO _x	121.77	40	Yes
SO ₂	2.81	40	No
VOC	25.88	40	No

BACT

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

Table II-2. Summary of Proposed BACT

EQUIPMENT	POLLUTANT	BACT DESCRIPTION
Process Heaters	NO _x	Ultra-Low NO _x burners, 0.03 lb/MMBtu
SRU Combustion Units	NO _x	Good Combustion Practice, 0.14 lb/MMBtu

SECTION III. DESCRIPTION OF PROCESSES

Sunoco's crude is received by pipeline and tanker truck. The crude is a mixture of purchased crude oils from various sources, which, when blended, has the required properties to make the lubricating oil products. Sunoco currently is operated primarily to produce high quality lubricating oils. Refinery fuel gases, propane, butane, isobutane, normal butane, gasoline, kerosene, No. 2 fuel oil, paraffin wax, petroleum coke, and Lube Extracted Feedstock (LEF) are some of the current byproducts from making the lube oils. LEF is a mixture of unfinished streams that may also be transferred to third party purchasers.

The specific types of refining process and support facilities in current use in the Sunoco Refinery are discussed in the following paragraphs. All of the process units and associated support equipment at Sunoco operate as a whole (one primary operating scenario). Individual units or pieces of equipment undergo periodic scheduled periods of shutdown for maintenance, but no one unit or piece of equipment has any permit restrictions on potential operating hours. Therefore, total potential operating hours per year for all equipment is 24 hours per day, seven days per week, for every day of the year.

The new processes from this project are listed first, then the processes with associated emissions, and then existing processes that are not affected by this project.

NEW PROCESSES

DIESEL HYDROTREATING UNITS (84 – DHT)

The DHT will consist of a standard, single cold separator design unit. The heart of the process is a fixed-bed catalyst. At high pressure, hydrogen reacts with sulfur present in the feed to form H₂S. Additional hydrogen is consumed in the reactor from the partial saturation of aromatics in the feed and the complete saturation of olefins present in the feed. The majority of the energy required to heat the feed stream in order to initiate the desulfurization reaction will be provided by recovery of the heat of reaction in a series of feed-effluent exchangers.

An additional amount of feed preheat will be provided by a 44.0 MMBtu/hr charge heater. The charge heater will be fired with sweetened RFG recovered from the new ATU. Reaction hydrogen will be provided exclusively from existing semi-regeneration reformer (#2 Platformer). The hydrogen will be compressed to the required reaction pressure by an electric-powered reciprocating gas compressor.

The hydrotreated diesel from the DHT unit will be processed in a new fractionation column where H₂S gas and light HCs will be stripped from the diesel. The stripper column will have a 53.7 MMBtu/hr process heater, and stripping steam will be used for vapor lift.

In addition to ULSD, the catalytic reaction in the DHT will produce 2,600 bpd of naphtha that must be returned to the refinery's existing crude atmospheric column for further processing. The DHT naphtha will contain 103 lb/hr of sulfur in the form of hydrogen sulfide (110 lb/hr H₂S). Essentially all of the incremental H₂S from the DHT naphtha will exit the top of the atmospheric column and will be distributed into 3 streams: T-4 Crude Unit Stabilizer; V-205 Light Ends

Recovery Unit (LERU) Unit DeEthanizer; and V-207 LERU Unit DePropanizer (Liquid Propane & Butane). Sour gas from the first two towers currently feed the refinery sour fuel gas system, while H₂S in the DePropanizer stream is scrubbed with potassium hydroxide (KOH) to convert the sulfur to K₂S salt, which is shipped offsite for disposal. After this project, the sour gas from the first two towers will be treated by the ATU.

AMINE TREATMENT UNIT (85 – ATU)

The stripper offgas and recycle purge gas will be directed to a new ATU downstream of the stripper. The ATU consists of an amine contactor and amine regenerator. The process removes H₂S from acid gas and hydrocarbon streams. The acid contaminants are absorbed by counter flowing amine solution (methyl diethanol amine - MDEA) in the contactor. The stripped gas is removed overhead, and the amine is sent to the regenerator. In the regenerator, the acidic components are stripped by heat and reboiling action and then processed in the SRU. The amine is recycled back to the contactor.

A stripper will remove H₂S from the rich amine, using steam as the heating medium.

The ATU treated gas will comply with NSPS Subpart J or Subpart Ja when it is promulgated. It will be routed to a new fuel gas drum equipped with an H₂S continuous emission monitoring device (CEM). A portion of the amine-treated refinery fuel gas (RFG) will be used as fuel for the diesel hydrotreater and sulfur process units; a portion will be used as fuel in existing reformer heaters (PH-5 and PH-6), and the remaining will be sent to the existing sour fuel gas distribution system. The sour gas from the amine contactor and the regenerator will be routed to the SRU for elemental sulfur recovery.

SOUR WATER STRIPPER (86 – SWS)

The proposed project will construct a 100 gallon per minute (gpm) Sour Water Stripper (SWS). The feed to the SWS is the new sour water from the DHT unit, and primarily water from the product steam stripping column overhead system. The product is stripped water that is fed to the desalters as wash water, with excess water being sent to the new API separator. The SWS will be reboiled by steam. Some of the steam will be generated by the SRU waste heat boiler, and the balance will come from the refinery “let down” steam.

The SWS acid gas will be routed to the SRU for recovery of the elemental sulfur and destruction of the ammonia. Oil recovered from the sour water flash drum and the sour water storage tank will be pumped to the existing refinery slop system for processing.

SULFUR RECOVERY AND TAILGAS TREATMENT UNITS (87 – SRU/TGTU)

The project will construct a SRU with a design capacity of 20.1 long tons per day (LTPD) and associated TGTU. The feed to the SRU/TGTU will be acid gases from the ATU and the SWS. The product from the SRU/TGTU is molten sulfur. The SRU will use standard Claus catalyst in the reactors. Offgas from the SRU will be routed to the TGTU which will use standard hydrotreating catalyst for the hydrogenation reaction.

The reduced gases from the TGTU will be circulated back to the SRU for elemental sulfur recovery. The tail-gas treatment and recirculation back to the SRU will guarantee sulfur

recovery efficiency of at least 99.8%. Offgas from the TGTU will be oxidized to SO₂ in an integrated natural gas-fired incinerator. The SRU/TGTU exhaust will be vented into the atmosphere through a common stack (ST-301).

ASSOCIATED UNITS

Cooling Water

A total cooling water demand of 6,000 gpm will be required by the Diesel Upgrade Project. The facility's existing cooling water infrastructure will be modified to accommodate the additional cooling water needs. Therefore, a new cell with mist eliminators will be included as part of the Diesel Upgrade Project.

Pressure Relief/Overpressure Control Valves

The pressure relief valves (PRV) and overpressure control valves from the diesel hydrotreater and sulfur processing units will be connected to the existing Coker flare. Flaring will only occur during upset or malfunction conditions.

Process Steam

The proposed project will have a net continuous process steam demand during normal operation. There will also be periodic demands for winterization steam and furnace purge steam (snuffing steam).

Storage and Loadout

The Diesel Upgrade Project will use existing storage tanks and loading racks to handle the ULSD product.

Treating the DHT Naphtha Stream

The new DHT will produce 2,600 bpd of naphtha containing 103 lb/hr of sulfur in the form of hydrogen sulfide (110 lb/hr H₂S). This additional naphtha from the DHT must be further processed in the existing crude unit's atmospheric column, resulting in incremental H₂S exiting the top of the atmospheric column. The H₂S and other light hydrocarbons such as propane from the top of the column are further treated at:

1. T-4 Crude Unit Stabilizer
2. V-205 LERU Unit DeEthanizer
3. V-207 LERU Unit DePropanizer (Liquid Propane & Butane).

The H₂S remaining in the V-207 LERU DePropanizer overhead and bottoms will be scrubbed with KOH. The sulfur reacts with the KOH to form K₂S salt which is disposed of. The offgas from the T-4 Crude Unit Stabilizer and the V-205 LERU Unit DeEthanizer are currently routed to the existing refinery sour fuel gas system.

Sunoco proposes to remove the incremental H₂S from the Stabilizer offgas and the DeEthanizer offgas by treating these streams in the new ATU. Routing the Stabilizer and DeEthanizer gas streams to the amine treating unit not only removes the incremental H₂S produced by the DHT naphtha, but removes H₂S from the existing base refinery operations as well. Sunoco estimates

that 912 tons of SO₂ emissions from burning refinery fuel gas in existing units will be reduced annually. By treating these off gas streams Sunoco is greatly reducing SO₂ emissions from combustion units fired by the refinery sour gas system.

It should be noted that processing the DHT naphtha in the crude unit atmospheric column does not increase energy needed by the process. The naphtha is added to the top pump around loop and acts as cooling reflux in place of ordinary water-cooled pump around reflux. Therefore there is no additional fired duty required by introducing the DHT naphtha into the column.

EXISTING PROCESSES

CRUDE DISTILLATION

The Crude Distillation Unit is the first process and is used to separate crude oil or mixtures of crude and other purchased crude fractions into specific boiling-range streams suitable either for further processing in downstream units or in some cases, for direct sale after mild treating or blending. The primary equipment associated with this operation is a main atmospheric pressure fractionator, a light ends fractionator called the "stabilizer tower," and two in-series vacuum distillation units. The atmospheric tower recovers streams that boil at approximately atmospheric pressure. The stabilizer tower feeds overhead gas to the crude tower and, at high pressure, effects a first separation of true gases (which go to the refinery fuel gas system) from crude gasoline. The vacuum towers recover high boiling point fractions that can be recovered only by lowering the pressure and operating at elevated temperatures. The energy for the distillation steps is provided by a main crude heater and two vacuum charge heaters, all gas fired. Other equipment important to crude and vacuum distillation is an extensive heat exchange system, a crude desalter system, and a vacuum producing system.

LIGHT ENDS RECOVERY UNIT (LERU)

The light gases from the Crude Unit Stabilizer are processed in a deethanizer tower and a depropanizer tower in the LERU. The deethanizer is a high-pressure fractionator that separates ethane and lighter fuel gases from propane and heavier hydrocarbons. The depropanizer tower is a pressurized tower that fractionates deethanizer bottoms into a liquid propane stream and a liquid mixed butane/pentane stream. The propane is treated with KOH for sulfur removal, stored in tankage, and sold as commercial liquefied petroleum gas (LPG). The mixed butane/pentane from the depropanizer is stored in pressurized storage prior to further fractionation. Energy for the LERU process is provided by steam passing through reboilers (heat exchangers).

ISOMERIZATION UNIT TOWERS

The isomerization reactors are shut down, but an associated fractionation system for separating manufactured and natural isobutane from normal butane remains in operation. Feed is the LERU butane/pentane stream from storage. The butane/pentane is brought from storage and treated with potassium hydroxide for sulfur removal and fed to the deisobutanizer which first creates a propane/isobutane feed for a depropanizer that separates propane as an overhead stream from isobutane as a bottoms stream. The propane is stored and sold as LPG. The isobutane is stored in a pressurized tank and sold as isobutane. Deisobutanizer bottoms are fed to a debutanizer for recovery of normal-butane as an overhead product (to sales or to gasoline blending), and pentane bottoms which goes to gasoline blending.

DEPENTANIZER AND NAPHTHA SPLITTER

The Crude Unit Stabilizer tower bottoms charge the fraction tower called the de-pentanizer. This de-pentanizer makes an overhead liquid stream called light straight run gasoline which goes to gasoline blending. Bottoms, called naphtha, are split via level control with part going to the Unifiner and part to Lube Extracted Feedstock (LEF) that is later shipped to the Sunoco Toledo Refinery or other third party purchasers. Splitter bottoms join crude naphtha as feed to the downstream Unifiner Unit. Energy for the de-pentanizer is supplied by a gas fired heater.

UNIFINER

The Unifiner Unit has the purpose of treating naphtha from the Crude Unit and the depentanizer bottoms in preparation for conversion to high-octane gasoline in the downstream No. 2 Platformer Unit. The Unifiner includes a hydrogen-treating reactor that removes sulfur and other contaminants that would be detrimental to the downstream Platformer. Other major equipment includes a hydrogen compressor, gas/liquid reactor effluent separator vessels, a stripper column to remove gases from the reactor product, and heat exchange systems. Two gas-fired heaters supply energy for the reactors and stripper column.

NO. 2 PLATFORMER

Unifiner effluent charges the Platformer, which catalytically converts the low-octane paraffin hydrocarbons to high-octane aromatics for gasoline blending. Naphtha feed is preheated by heat exchange, charged to a series of four endothermic catalytic reactors (four gas-fired heaters supply the heat of reaction), flashed to separate gas from product, and distilled through a debutanizer tower. The debutanizer is energized by a gas-fired reboiler heater. Hydrogen and other light gases are by-products that are primarily sent to refinery fuel gas, although a hydrogen-rich stream is used to provide hydrogen to the Unifiner reactors and the lube hydrotreater.

DEASPHALTER

The Deasphalter Unit processes heavy bottoms from the second stage vacuum tower at the Crude Unit. Two parallel solvent extraction towers mix feed and propane solvent and produce two streams, one that is paraffinic and suitable as feedstock for lube manufacture in the downstream Lube Extraction Unit, and a second that is asphaltic that charges the Coker Unit. Some of the paraffin stream is also blended to the lube-extracted feedstock that is exported by pipeline to the Sunoco Toledo Refinery or third party purchasers. The Deasphalter Unit employs other towers, vessels, pumps, heat exchangers, etc., to recover propane solvent from the product streams. Propane is recycled to the front-end extraction towers. Two gas fired process heaters and steam from the refinery system provide energy for the extraction process and for solvent recovery operations.

LUBE OIL EXTRACTION AND HYDROGENATION

This unit is charged with vacuum gas oil fractions and paraffinic deasphalted oil which flows into two parallel counter-current solvent extraction towers that utilize furfural as a solvent. As a result, two streams are produced, a waxy paraffinic stream suitable for lube oil manufacture and an aromatic stream that is either blended with lube oil extracted feedstock for pipeline shipment to the Sunoco Toledo Refinery or sold as extract product. The waxy paraffinic stream is fed to a hydrogenation unit to improve its stability and remove impurities before going to a downstream dewaxing operation. The hydrotreater is a fixed bed catalytic unit that uses hydrogen from the

No. 2 Platformer. The unit employs towers, vessels, heat exchangers, pumps, etc., to remove and recycle the furfural solvent from the product streams. Three gas-fired heaters provide energy for the process.

MEK DEWAXING UNIT

This unit removes wax from the hydrotreated paraffins from the Lube Extraction Unit. The process employs two solvents in mixture, toluene and methyl-ethyl-ketone. Fabric filters on rotating drums are used to physically separate wax from oil. A propane refrigeration system provides cooling to effect wax precipitation out of oil/wax solutions. Paraffin streams are fed in blocked out batches (the boiling range of the various batches having been set when recovered as separate streams at the Crude Unit vacuum towers). The separated oil is stored and used for finished lube oil blending. The separated wax is stored and sold as various melt point products. Waxes with a melt point above about 116 °F are further processed through a downstream Percolation Filtration Unit. The unit equipment includes oil/solvent contactors, rotating drum fabric filters, towers and vessels for solvent recovery and recycle, a propane refrigeration compressor system, a flue gas compressor system associated with the fabric filters, pumps, heat exchangers, etc. Two gas fired process heaters are employed, one for oil/solvent separation, and one for soft wax/solvent separation.

WAX PERCOLATION FILTRATION UNIT

This unit produces several grades of wax but no longer produces food grade waxes. Tanks, LDAR components and one gas fired heater are the only processes operational in this unit.

COKER UNIT

Sunoco's Coker Unit produces solid coke in a batch process. The Coker Unit equipment list includes two gas fired process heaters, two coke drums, a main fractionator, and other towers, vessels, pumps, heat exchangers, etc. The Coker Unit alternates the process between two vessels called drums. One drum is being charged for processing while the other is being emptied or "de-headed." The process begins by charging one of the coke drums with the asphaltic stream from the Deasphalting Unit. The process thermally separates the heavy molecules into carbon (coke) and light hydrocarbons. The charge is heated to 900°F using two gas-fired process heaters and then is allowed to have residence time while the coke and the light hydrocarbons separate. The light hydrocarbons flows/charges the product fractionation system (a part of the Coker Unit) for separation into gas for refinery fuel, and liquids which are pipelined to the Sunoco Toledo Refinery or to third party purchasers, and gasoline for recovery back through the Crude Unit stabilizer. After a drum is de-headed the coke is cut using high pressure steam and the drum is cleaned out with steam for the next batch. Coke is stored in piles on-site, for bulk shipment by rail or trucks. Air emissions from handling the finished coke are insignificant.

LUBE/WAX BLENDING AND SALES/SERVICE OPERATIONS

This refinery's primary purpose is to produce finished paraffinic lubricating oils. These waxes are also an important by-product of lube oil manufacturing process. To provide the specialty products required by Sunoco's diverse customers, there is a product blending and shipping operation at the site. The blending primarily occurs in fixed cone roof tank areas. Packaging and package storage is conducted in the Lube Service Center building. Shipment is by bulk in tank trucks and tank railcars.

STEAM GENERATION

In an area called "No. 5 Boilerhouse" (No. 4 Boilerhouse was dismantled in the 1970s), there are seven gas-fired boilers that produce steam for general refinery use. There are five individual boiler units numbered Nos. 3, 4, 7, 8, and 9. Boilers No. 1 and 2 have been shut down, generating NO_x credits. In addition to the steam generated by these boilers, steam will be produced from one or two temporary boiler(s). One temporary boiler is in place with startup expected in Feb 2008.

WASTEWATER TREATMENT

Facility wastewaters are conveyed in combined storm/process sewers, through oil/water separators and to a treatment area that employs storm surge capacity, clarification, dissolved air floatation, equalization, and aerobic waste digestion. Treated water is discharged to the Arkansas River. Recovered sludges and oil are separated at a centrifuge facility and the oil is fed to the Coker Unit or Crude Unit.

COOLING TOWERS

The refinery employs 7 non-contact cooling towers. These are systems that circulate captive waters that provide a heat sink for various process units or equipment. Water is circulated through heat exchangers to indirectly cool hydrocarbon or other streams. Hot water from these exchangers is collected by pipelines and sprayed over packed towers in counter current flow to atmospheric air. The evaporation of a portion of the hot (typically 100 to 120°F) circulated water provides cooling to about 85°F (summer) for recirculation back to the heat exchangers. The white plumes observed from these towers are the evaporated water that sometimes re-condenses cloud-like at certain atmospheric conditions. The cooling towers have not used chrome-based systems since before 1994, are not subject to NESHAP MACT Subpart Q, and are trivial sources named in Appendix J of OAC 252:100.

FLARE STACKS

The refinery employs four vertical, piloted flare stacks for the emergency containment and combustion of certain hydrocarbon releases. Various equipment at Sunoco are fitted with pressure relief valves to protect against overpressure conditions. These pressure relief valve outlets discharge into a gas collection flare piping system. Each flare stack uses a continuous pilot light that assures ignition of any gaseous discharges. Each flare also uses a steam system that supplies a constant source of steam for mixing with the gas being flared (as needed) to reduce/prevent the combustion products from smoking.

LOGISTICS AND STORAGE

The Sunoco logistics system involves feed and product receipt and shipment systems, as well as extensive internal movements. Crude feed material is primarily received by pipeline into large tanks. Product shipments are also made by pipeline, tank truck, rail tank car, and package truck trailer. This refinery does not have a marine terminal. There is an extensive storage tank system that handles crude feeds, finished products, and process intermediates. Types of material are generally in common geographical areas, but there are many exceptions due to the long history of the site.

SULFUR AND OTHER IMPURITY TREATMENTS

This refinery processes feeds that are low in sulfur content and does not employ a FCCU. This project will install the first large hydrotreater, amine gas scrubber, sour water stripper, and elemental sulfur recovery unit at this refinery. Refinery process offgases often contain significant amounts of sulfur. These offgases flow to a RFG system and can be burned only in grandfathered fuel-burning units. Refined product sulfur impurities are addressed within specific process units by caustic or chemical treatment steps.

SECTION IV. PROJECT EMISSIONS

The Tulsa Refinery is an existing PSD major source. This section presents the emission calculation methodology used to determine PSD applicability for the new, modified, and associated units, including process heaters, SRU unit, equipment leaks, cooling towers, storage tanks, and emissions associated with increased steam production.

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

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

The following sections detail each of the steps outlined above.

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

The maximum potential emissions from each new, modified, and associated source were determined for this project. For each PSD pollutant, the baseline actual emissions are subtracted from the potential emissions to determine the emissions increase for each new, modified, or associated source. Baseline actual emissions are defined in OAC 252:100-8-31 as “the average

rate in tons per year at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding the date a complete application is received.” For new emissions sources the baseline actual emissions are zero. For this project, Sunoco averaged emissions from the 2005 and 2006 emission inventories to determine baseline actual emissions for each pollutant from a given source. Emission decreases are not considered in this step. The emissions increases for each new, modified, and associated source are shown in the following sections.

Process Heaters

1. Emissions Increases Used for Both PSD Applicability and PSD Netting

Two new heaters will be installed as part of the DHT project. The heaters will be fired with sweetened RFG recovered from the new ATU. The heaters will be equipped with Ultra-Low NO_x burners (ULNB). Hourly values of VOC, PM₁₀, and CO have been increased by 50% to allow for periods of startup and shutdown.

TABLE IV-1A. PROCESS HEATER EMISSIONS RATES

Process Heaters	Emissions										
	MMBtu/hr	NO _x		VOC		PM ₁₀		CO		SO ₂	
		lb/MMBtu	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/MMBtu	TPY
DHT Heater (B4101)	44.0	0.03	5.78	0.43	1.25	0.59	1.72	6.52	19.05	0.03	2.42
DHT Heater (B4102)	53.7	0.03	7.06	0.53	1.52	0.72	2.10	7.96	23.24	0.03	2.95
Totals	-	12.84	0.96	2.77	1.31	3.83	14.48	42.29	-	5.36	

The emissions are based on the following factors and continuous operation.

TABLE IV-1B. PROCESS HEATER EMISSIONS FACTORS

Contaminant	Emission Factor w/ Safety Factor	Unit	Basis	Emission Factor	Unit
NO _x (new unit)	0.03	lb/MMBtu	Manufacturer Guarantee		
VOC	0.0065	lb/MMBtu	AP-42 + 20% safety factor	5.5	lb/MMscf
PM ₁₀	0.0089	lb/MMBtu	AP-42 + 20% safety factor	7.6	lb/MMscf
CO	0.0988	lb/MMBtu	AP-42 + 20% safety factor	84	lb/MMscf
SO ₂	0.013	lb/MMBtu	Site-specific factor		

Associated Boilers

Associated emissions increases for boilers are included in this permit application for the purpose of verifying PSD applicability and air quality modeling. The boilers are included as a result of an incremental increase in steam demand due to the DHT project. The project does not involve physical modifications to any associated emission units. These emission units will continue to operate in compliance with currently applicable rules, regulations, and permit conditions.

Therefore, this permit does not include emission limits, or specific conditions for the associated emission units.

TABLE IV-2. BOILER EMISSIONS INCREASE

Boiler incremental increase due to increased steam demand from Boiler House	Emissions (TPY)				
	NOx	VOC	PM/PM ₁₀	CO	SO ₂
Energy Increase	59.31	1.16	1.61	17.79	191.95

The emissions are based on the worst case emission factors (280 lb NOx/MMSCF and a site specific factor for SO₂ of 1.11 lb/MMBtu) for the least efficient boilers (No. 3 & 4) to produce the incremental steam.

Sulfur Recovery Unit (SRU) / Tail Gas Treatment Unit (TGTU)

A new SRU/TGTU will be installed as part of the DHT project. The SRU/TGTU will be fired with sweetened RFG recovered from the new ATU.

TABLE IV-3A. SRU/TGTU EMISSIONS RATES

SRU	Emissions									
	NOx		VOC		PM ₁₀		CO		SO ₂	
	lb/MMBtu	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	ppmv	TPY
SRU Unit	0.14	4.4	2.41	7.03	1.62	4.73	1.00	2.93	250	15.93

The emissions are based on the following factors and continuous operation.

TABLE IV-3B. SRU/TGTU EMISSIONS FACTORS

Contaminant	Emission Factor	Unit	Source
NOx	0.14	lb/MMBtu	Fuel fired basis - Incinerator burner vendor estimate
VOC	18.60	lb/MMscf stack gas	Incinerator burner vendor estimate of (ppm) 160
PM/PM ₁₀	0.15	lb/MMBtu	Fuel fired basis - Incinerator burner vendor estimate
CO	7.75	lb/MMscf stack gas	Incinerator burner vendor estimate of (ppm) 105
SO ₂	42.17	lb/MMscf stack gas	NSPS maximum allowable of (ppm) 250
H ₂ S	0.90	lb/MMscf stack gas	NSPS maximum allowable of (ppm) 10

Tanks

Two new tanks will be constructed as part of the DHT project. One will be an IFRT sour water tank and the other a FRT amine tank. The sour water contains H₂S and NH₃.

TABLE IV-4A. NEW TANK EMISSIONS RATES

Tanks	Emissions (TPY)	
	VOC	H ₂ S
Sour Water TK21T-014	-	0.09
Amine TK85T-614	-	-

There will be an increase in throughput of existing distillate tanks. The following table shows the total increase from new and existing tanks.

TABLE IV-4B. EXISTING TANK EMISSIONS INCREASE

Tanks	Emissions (TPY)					
	NOx	VOC ¹	PM/PM ₁₀	CO	SO ₂	H ₂ S
Total	-	4.08	-	-	-	-

¹ Emission estimates were generated through Tanks4.0.9d. This program contains default chemical properties for petroleum distillates, crude oils and organic liquids. From the Petroleum Distillate category, distillate fuel oil no. 2 was selected to represent the properties of distillates, sour water and amine tank contents. Estimated emissions are conservatively high as the anticipated vapor pressures of stored material are less than Tanks4.0.9d's default diesel VPs.

Cooling Towers

Modifications to one existing cooling tower are included in the proposed project. Cooling Tower #9 (Butane Splitter CT) will receive a new cell with a capacity of 6,000 GPM. Emission calculations for total dissolved solids (TDS) concentration (5,000 parts per million [ppmw]) and drift rate (0.005%) are based on current design information. Emissions for VOC are calculated using the controlled emission factor for petroleum refinery cooling towers presented in AP-42 (9/91) Table 5.1-2. Emission calculations are presented in Tables IV-5A and IV-5B.

TABLE IV-5A. COOLING TOWER PM₁₀ EMISSIONS INCREASE

Emissions Unit	TDS, ppmw	Drift Rate, %	Recirculation Rate, gpm	PM ₁₀ , lb/hr	PM ₁₀ , TPY	Past Actual, TPY	Net, TPY
Cooling Tower #9	5,000	0.005	6,000	0.75	3.29	0.0	3.29

TABLE IV-5B. COOLING TOWER VOC EMISSIONS INCREASE

Emissions Unit	Recirculation Rate, gpm	Emission Factor, lb/10 ⁶ gallon	VOC, lb/hr	VOC, TPY	Past Actual, TPY	Net, TPY
Cooling Tower #9	6,000	0.7	0.25	1.10	0.0	1.10

Equipment Fugitives

The proposed project will result in an increase in VOC emissions from equipment leaks due to the installation of equipment such as flanges, valves, compressors, pressure relief valves, and pumps. The emissions increases for equipment leaks are calculated using design-basis component counts along with emission factors that were developed specifically for the Tulsa Refinery based on the LDAR testing for 2005 and 2006 and the protocol in EPA Document EPA-453/R-95-017, November 1995, Protocol for Equipment Leak Emission Estimates. Drain emission factors are assumed to be equal to the compressor/other factor. The factors and emissions of VOC and H₂S are given in the following table.

TABLE IV-6A. LDAR EMISSIONS RATES

Components Added	Number of Components	Emission Factors, lb/hr-source	VOC, TPY	H ₂ S, TPY
	VOC / H₂S			
GGG Components Added:				
Valves	2,399 / 460	0.0004	4.61	0.88
Flanges / Connectors	6,445 / 138	0.0001	3.73	0.08
Pumps	9 / 32	0.0003	0.01	0.05
Compressors / Others (Including Sampling Connections)	27 / 7	0.0014	0.09	0.04
Pressure Relief Valves to Flare ¹	15 / 28	0.0006	0.04	0.07
QQQ Components Added:				
Others (Including Process Drains)	128/69	0.0014	0.78	0.42
Overall Net Emissions Change			9.26	1.54

¹ The flare control efficiency is assumed to be 98%.

Loading Emissions

There will be an increase in throughput of existing truck and rail car loading. The following table shows the total increase from truck and rail car loading.

TABLE IV-7. LOADING EMISSIONS RATES

Incremental Increase from Loading	Emissions (TPY)				
	NO _x	VOC	PM/PM ₁₀	CO	SO ₂
All Loading	-	0.48	-	-	-

Emissions Increases Summary

The following table summarizes the project emissions increases for all new and associated sources that will be used for PSD Applicability.

TABLE IV-8. PROJECT SUMMARY EMISSIONS RATES

Source	NO _x		VOC		PM/PM ₁₀		CO		SO ₂		H ₂ S	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Process Heaters	2.93	12.84	0.63	2.77	0.87	3.83	9.66	42.29	1.22	5.36	NA	NA
Steam & Energy Increase	13.54	59.31	0.27	1.16	0.37	1.61	4.06	17.79	43.82	191.95	NA	NA
SRU Impact	1.0	4.4	1.60	7.03	1.08	4.73	0.67	2.93	3.64	15.93	0.00	0.34
Tanks	NA	NA	0.93	4.08	NA	NA	NA	NA	NA	NA	0.02	0.09
Fugitive (LDAR)	NA	NA	2.11	9.26	NA	NA	NA	NA	NA	NA	0.35	1.54
Cooling Tower	NA	NA	0.25	1.10	0.75	3.29	NA	NA	NA	NA	NA	NA
Loading	NA	NA	0.11	0.48	NA	NA	NA	NA	NA	NA	NA	NA
TOTALS	NA	76.55	NA	25.88	NA	13.45	NA	63.01	NA	213.24	NA	1.97

PSD Applicability

The following table shows the total applicable emission increase for each PSD regulated pollutant. The total project emission increase for each pollutant is compared to the PSD SER for that pollutant to determine if a PSD netting analysis is required. As shown in the table the emission increase for NO_x and SO₂ is above the SER. Therefore, a PSD netting analyses, based on steps 2 through 6 of the PSD netting procedure, is required for NO_x and SO₂.

TABLE IV-9. PROJECT EMISSION INCREASE FOR PSD REGULATED POLLUTANTS

Pollutant	Emission Rate, TPY	PSD Significant Emission Rate, TPY	PSD Netting Analysis Required?
NO _x	76.55	40	Yes
SO ₂	213.24	40	Yes
CO	63.01	100	No
VOC	25.88	40	No
PM ₁₀	13.45	15	No

Step 2. Contemporaneous Period

According to OAC 252:100-8-31, “an increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within 3 years before the date that the increase from the particular change occurs”. DEQ has interpreted the contemporaneous period to be three years prior to the start of construction through the start of operation. Therefore, for this project, the contemporaneous period begins May 1, 2005 and ends at startup of operations.

Step 3. Emissions Increases and Decreases During the Contemporaneous Period

Contemporaneous emissions increases and decreases are those emissions associated with new construction, a physical change, or change in the method of operation of a source that begins operation during the contemporaneous period. Contemporaneous emissions decreases are those emissions decreases associated with new construction, a physical change, change in the method

of operation of a source, or reductions in actual emissions from a federally-enforceable emission limit that begin operation during the contemporaneous period.

Project-Related and Consent Decree-Related Emission Decreases

Sunoco proposes to remove the H₂S from the Stabilizer offgas and the DeEthanizer offgas by treating these streams in the new Amine Treating Unit. Routing the Stabilizer and DeEthanizer gas streams to the amine treating unit not only removes the H₂S from the existing base refinery operations, but removes the incremental H₂S produced by the DHT naphtha as well. Sunoco estimates that 912 tons of SO₂ emissions from burning refinery fuel gas will be reduced annually, but the Consent Decree only allows credit for a 250 TPY reduction of SO₂.

Other Contemporaneous Emission Increases and Decreases

There was one project to add two temporary boilers (M-12) and one project to change the number of burners in an existing heater (M-13) during the contemporaneous period. The (M-12) project added 31.22 TPY of NO_x and 0.57 TPY of SO₂. The (M-13) project added 14 TPY of NO_x and 39 TPY of SO₂.

Step 4. Creditable Emissions Changes

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

This is the first PSD permit for the Sunoco Tulsa Refinery. There have been three minor modification permits applied for in the contemporaneous period but none have been issued yet. One was an administrative amendment with no change in emissions. The other two projects have been included in the PSD netting.

Step 5. Amount of Emissions Increase and Decrease

The Consent Decree allows a credit for up to 250 TPY reduction of SO₂. The (M-12) project added 31.22 TPY of NO_x and 0.57 TPY of SO₂. The (M-13) project added 14.0 TPY of NO_x and 39.0 TPY of SO₂ based on the conservative approach of the difference of the potential to emit and the baseline actual emissions.

Step 6. PSD Review Applicability

The following table summarizes the significant net emissions increase for each significant PSD pollutant for this project and the contemporaneous period.

TABLE IV-10. SIGNIFICANT NET EMISSIONS INCREASES

Pollutant	Emission Increase, TPY	Creditable Contemporaneous Emissions, TPY	Net Emission Increase, TPY	PSD Significant Emission Rate, TPY	Subject to PSD Review?
NO _x	76.55	31.22 + 14	121.77	40	Yes
SO ₂	213.24	-250 + 0.57 + 39	2.81	40	No

The project is subject to PSD review for each regulated pollutant for which the sum of all creditable emissions increases and decreases results in a significant net emission increase. Additional prospective and creditable emission reductions sufficient to provide for a less than significant net emission increase at the source may be proposed to avoid PSD review. As shown in Table IV-10, a PSD review is not required for SO₂. Emissions of NO_x require a full PSD review. The PSD review for NO_x is presented in Section V.

SECTION V. PSD Review for Pollutant NO_x

A full PSD review consists of the following steps:

1. Determination of BACT.
2. Analysis of air quality impacts. This analysis includes:
 - Description of dispersion model and procedures
 - Determination of air quality impact significance
 - Determination of pre-construction monitoring requirements
 - Compliance with National Ambient Air Quality Standards (NAAQS)
 - Compliance with available PSD increments
3. Evaluation of source-related impacts on growth, soils, vegetation, and visibility.
4. Evaluation of Class I Area impacts.

In addition, the proposed project is subject to certain federal and state standards including, but not limited to, NSPS 40 CFR Part 60, Subparts A, J, GGG, and QQQ, and NESHAP 40 CFR Part 63, Subpart CC (MACT I), and Subpart UUU (MACT II). NESHAP Subpart DDDDD has been vacated and USEPA is currently revising this regulation. Sunoco will be compliant with the final NESHAP DDDDD when promulgated.

1. Determination of BACT

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

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

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

- Step 1. Identify Available Control Technologies
- Step 2. Eliminate Technically Infeasible Options
- Step 3. Rank Remaining Control Technologies by Control Effectiveness
- Step 4. Evaluation of Remaining Control Technologies Based on Energy, Environmental, and Economic impacts
- Step 5. Select BACT and Document the Selection as BACT

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

The new NO_x emission sources for this project are:

- A. Process heaters B4101 and B4102.
- B. SRU Combustion Unit.

These BACT evaluations are based on the following resources:

- Engineering experience;
- EPA’s RACT/BACT/LAER Clearinghouse database search;
- EPA’s “*Alternate Control Techniques Document for NO_x Emissions*” June 1994, and
- EPA’s Air Pollution Technology Fact Sheets.

The RACT/BACT/LAER Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies that have been approved in PSD permits as BACT for numerous types of process units. Process units in the database are grouped into categories by industry.

NO_x Emissions

NO_x emissions are generated from the high temperature dissociation of atmospheric nitrogen molecules and their subsequent reaction with oxygen to form nitrogen monoxide (NO) or nitrogen dioxide (NO₂) (thermal NO_x) and from chemically bound nitrogen in the fuel (fuel NO_x). Thermal NO_x is primarily formed at temperatures above 1,300°C; therefore, limiting the temperature of the flame can control its generation. Fuel NO_x is formed when the fuel nitrogen is converted to hydrogen cyanide and then oxidized to form NO that further oxidizes in the atmosphere to NO₂. Since the first step of the oxidation occurs in the combustion chamber, providing an oxygen-deficient atmosphere in the combustion chamber can significantly reduce NO, and thereby NO₂ formation.

Some combustion processes can be modified to minimize NO_x emissions by reducing:

- peak flame temperature;
- gas residence time in the flame zone; and
- oxygen concentration in the flame zone.

The RACT/BACT/LAER Clearinghouse (RBLC) database contains information from early notification submittals and air permits received from various state and local air pollution control programs in the United States. The data assist companies in determining what types of controls and pollution prevention measures have been applied to and/or are required for various sources and the effectiveness of these technologies. The permit application provided results for the lowest emission rates for NO_x (0.03 lb/MMBtu). These results were obtained from the EPA's RBLC database for the similar categories combustion units.

Step 1. Identify Available Control Technologies

To comply with the "top-down" process for the BACT analysis, the following subsection contains a technology-by-technology evaluation starting with the most stringent control option. These various technologies are discussed in detail under the evaluation for the process heaters and are not repeated for the rest of the evaluated units.

BACT for Process Heaters with Heat Rate of 44.0 MMBtu/hr and 53.7 MMBtu/hr

The proposed Diesel Upgrade Project will install two RFG-fired process heaters with heat input of 44.0 MMBtu/hr and 53.7 MMBtu/hr respectively. RFG and natural gas are known to have low fuel-bound nitrogen level. Therefore, the primary focus of this evaluation is the reduction of thermal NO_x.

The following paragraphs discuss possible thermal NO_x control technologies in decreasing order of control efficiencies.

Selective Catalytic Reduction (SCR)

An SCR system utilizes the abilities of certain compounds, most commonly urea or ammonia, to react with NO_x emissions, to form benign chemical compositions. A controlled amount of the reactive chemical is sprayed into the exhaust stack, and is met by an intricate arrangement of precious metals which act as catalysts for the chemical reaction. Historically, SCRs have been very successful NO_x control devices. The drawbacks of SCRs are that they tend to have high capital costs, and the process heater exhaust stream must meet certain temperature and pressure values for the device to function properly.

Past examples indicate that SCRs have achieved significant NO_x reductions for natural gas and RFG-fired process heaters. At optimum operating conditions, NO_x reductions of approximately 90% are likely to be realized by the installation of an SCR system. The efficiency and final emissions rates are very difficult to predict as they depend on the SCR unit and the pressure and temperature achieved in the stack. Based on data found in the RBLC, it is predicted that the SCR will achieve approximately 85% NO_x reductions. Although the ammonia feed rates in SCR systems are designed to minimize any release of ammonia, most manufacturers specify an ammonia slip rate between 2 and 10 ppmv.

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction (SNCR) was also reviewed for potential application to the proposed process heaters. SNCR requires excellent flue gas to ammonia (urea) mixing ratio which requires large combustion chamber volumes and residence time. This technology also requires a precise and stable temperature window in the boiler at which to inject the ammonia or urea.

The process heaters are factory-packaged units with relatively small combustion chamber. The process heaters do not have adequate room in their combustion chambers to provide the required flue gas-to-ammonia mixing ratio for effective performance of the SNCR. Although the heaters will operate the equivalent of 8,760 hours per year, they will serve a broad range of process duties. The likely sporadic operation with load following over a turndown range will create wide firing and temperature distribution variations within the combustion chamber that is inherently too small for ammonia and NO_x to effectively contact each other. This will preclude the ability to utilize SNCR for NO_x control in these units.

SNCR is therefore determined to be not technically feasible for application to the proposed RFG-fired process heaters.

Low-NO_x Burners with Flue Gas Recirculation

The use of low-NO_x burners is a widely accepted method to control NO_x emissions from combustion sources. Low-NO_x burners are developed by burner and boiler manufacturers and

therefore exhibit a wide variety of designs. However; the principle for all NO_x burners is the same: the burners inherently generate lower NO_x emissions due to internal staging of fuel combustion. Burner staging delays combustion and reduces the peak flame temperature, thus reducing thermal NO_x formation. High levels of excess air within the primary combustion zone reduce the temperature. Secondary fuel is injected into the combustion zone under high pressure. This action results in heat being transferred from the first stage combustion products to the second stage combustion. As a result, the second stage combustion is achieved at lower partial pressures of oxygen and temperature than would normally be encountered.

Flue gas recirculation (FGR) is a technique in which a portion of exhaust gas or flue gas is recycled to a point where it joins and, therefore, dilutes the inlet combustion airflow. The dilution serves to lower peak flame temperature, thus reducing thermal NO_x formation.

All identified top-down BACT decisions for similar packaged process heaters conclude that Ultra-Low NO_x Burners (ULNB) represents the best practical and cost effective alternative for this particular source type. Most ULNB's sold by the major manufacturers utilize internal "micro combustion staging", whereby flue gas is internally recirculated into the highest temperature portion of the flame, and additional air is added downstream to complete burn out of products of incomplete combustion. From the RBLC data, the lowest emission rate that can be achieved when burning RFG with this technology is 0.03 lb NO_x / MMBtu.

Staged Firing

Staged firing is a technology that reduces NO_x formation by operating outside the normal stoichiometric ratio; it includes over fire air, burners-out-of-service, and biased firing methods.

Burners Out of Service, Separated Over-fire Air, and Gas Reburn

Various staged combustion techniques have been applied to vertically oriented, field erected combustion sources, including Burners Out of Service (BOOS) and, Separated Over-fire Air (SOFA). All of these technologies seek to limit the formation of NO_x by vertical combustion staging in the furnace of field-erected combustion sources, where sufficient volume and residence time exists to starve the high temperature combustion zone of oxygen, and then adding the oxygen back to complete combustion in the upper section of the furnace. No listings of RFG-fired process heaters were found in the RBLC which employ burners out of service, separated over fire air, or gas reburn technologies for control of NO_x. Nor were any of these technologies discussed in the EPA's ATC Document as applicable to this type of process heater. None of these methods of NO_x control are determined to be technically feasible for application to the proposed process heaters.

Step 2. Eliminate Technically Infeasible Options

SNCR can be eliminated as technically infeasible. Therefore, all the rest of the technologies mentioned above will be examined for energy, environmental, and economic impacts.

Step 3. Ranking of Remaining Control Technologies by Control Effectiveness

The following table lists the technologies identified as possible NO_x reduction technologies for the proposed combustion sources at the Sunoco’s Tulsa facility along with their expected percent reductions.

TABLE V-1. Possible Control Technologies for NO_x Emissions

Control Technology	Theoretical NO_x Reduction¹
Combustion Modifications:	
Low-NO _x burners and flue gas recirculation	40 – 60%
Air staging	20 - 40%
Post Combustion Modifications:	
Selective catalytic reduction (SCR)	80 - 90%
Selective non-catalytic reduction (SNCR)	30 - 50%

NOTE:

1. Theoretical Reduction Efficiencies based on the publication: “*Best Achievable Control Technology for Air Pollution Control: Analysis Guidance and Case Studies for North America*,” by North American Commission of Environmental Corporation. – February 2005

Step 4. Evaluation of Remaining Control Technologies

Selective Catalytic Reduction (SCR)

While an SCR is not normally considered a powered device, it will necessitate slight increase in energy consumption. Since hardware will be installed directly into the exhaust stack, the exhaust fans will have to do more work to achieve an appropriate flow rate. Furthermore, the ammonia sprayers draw small amounts of power as well. Operating an SCR also implies certain indirect increases in energy consumption, such as the energy required to create and transport ammonia.

From RBLC search, the use of SCR system to control NO_x emission from an RFG-fired or natural gas-fired process heater or any other combustion unit is cost effective when the rated heat input exceeds 280 MMBtu/hr. Other reviewed air pollution control technology sources were in agreement with the RBLC results. Therefore, SCR technology is not considered economically viable for the process heaters.

The remaining control technologies are less effective than ULNB so they are eliminated.

Step 5. Select BACT and Document the Selection as BACT

BACT Selection for the Process Heaters

The 44.0 MMBtu/hr and the 53.7 MMBtu/hr RFG-fired heaters will be equipped with ULNB. The low NO_x emissions for the process heaters (0.03 lb/MMBtu) agrees with the emissions rates

identified in the RBLC search and also are below the EPA's new source performance standard for these units. This low NO_x emission rate is readily achievable due to the pre-installed ULNB. Therefore, the selected BACT for the heaters is ULNB at an emission rate of 0.03 lb NO_x / MMBtu (3-hour average).

BACT Evaluation for the SRU Combustion Unit

A SRU will be an integral part of the Diesel Upgrade Project. The SRU unit is equipped with a natural gas/RFG-fired combustion unit of insignificant heat rating (<10 MMBtu/hr).

Review of the RBLC did not reveal any apparent cost effective control technology for similar combustion units. A listed company operating a similar combustion unit achieved NO_x emission rate of 1 lb/hr through combustion control and good operating practices. Based on 7.2 MMBtu/hr unit rating, the equivalent emission rate is 0.14 lb/MMBtu. Therefore, a maximum NO_x emission rate of 0.14 lb/MMBtu (3-hour average) is the selected BACT for the SRU Combustion Unit and will be accomplished by good combustion practices.

Analysis of Air Quality Impacts

The Sunoco Tulsa Refinery is located in Tulsa County, which is currently designated attainment or unclassified for all criteria pollutants, and there are no areas classified as non-attainment within 50 kilometers of the refinery. This modification will result in emission increases sufficient to trigger the PSD requirements codified in 40 CFR Part 52.

PSD is a construction-permitting program designed to ensure air quality does not degrade beyond the NAAQS or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then they trigger this review process. EPA has provided modeling significance levels (MSL) for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. Air quality impact analyses were conducted to determine if ambient impacts would be above the EPA defined modeling and monitoring significance levels. If impacts are above the MLS, a radius of impact (ROI) is defined for the facility for each pollutant out to the farthest receptor at or above the significance levels. If a radius of impact is established 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 for the Class II area.

Sunoco has prepared an air quality analysis in accordance with the procedures and methodology presented, which are consistent with guidance provided by the Oklahoma Department of Environmental Quality (ODEQ) and Environmental Protection Agency (EPA). The results of this air quality analysis show that the proposed emissions authorized in this permit will not cause or contribute to an exceedance of the NAAQS or significant PSD increment consumption.

Description of dispersion model and procedures

Sunoco performed an air dispersion modeling analysis for the proposed Diesel Upgrade project using the AMS/EPA Regulatory Model (AERMOD). AERMOD is an EPA-approved, steady state Gaussian plume model capable of modeling multiple sources in simple and complex terrain. AERMOD is the model currently approved for industrial sources and PSD permits, it is an appropriate model for the facility, and ODEQ requested that Sunoco demonstrate regulatory compliance through its use.

Potential Emissions and Stack Parameters

The air dispersion modeling evaluated potential emissions of NO₂ from new combustion sources, and incremental increase in steam from existing boilers. NO₂ from the incremental increase in steam utilization is the difference of the projected actual emission to the current actual emission from worst case boiler. The worst case boiler was assessed based on three criteria: NO₂ emission rates, stack parameters (flowrate, temperature, diameter, etc.), and proximity to the property line. The boiler stack that presented the worst scenario was selected for the model.

There are several types of emission sources that can be modeled in AERMOD. These source types include point sources, area sources, and volume sources. The emission sources modeled in this exercise are point sources, which consist of emission units that release all of their emissions out of a stack. A summary of the potential emissions and incremental steam requirement from the proposed facility are presented in the following table along with proposed emission rates and stack parameters.

TABLE V-2. NO₂ Emission Unit Parameters

Parameters	Stack Data			
	Process Heater (B4101)	Process Heater (B4102)	Incremental Steam (Existing Boilers 3 & 4)	SRU (ST-301)
UTM Easting (X-m)	768027.42	768027.42	768582.00	767926.70
UTM Northing (Y-m)	4003561.00	4003551.92	4003598.00	4003531.50
Elevation (Z-m)	193.9	193.9	195.07	193
Stack Height (Feet)	90	90	110	150
Stack Temperature (°F)	1,000	860	267.8	1,350
Stack Diameter (Feet)	3.5	4.3	10.5	10.5
Stack Flow rate (acfm)	10,500	13,500	5,0851	1,826.4
NO _x (lbs/hr)	1.32	1.61	14.16	1.0

Modeling Methodology

AERMOD model was used to estimate potential air quality impacts from the proposed Diesel Upgrade project. The modeling analysis described in this report evaluated potential emissions from the proposed project for compliance with all applicable standards under the PSD

regulations. These standards may be separated into two parts: Class II air quality standards and Class I air quality standards and related values (AQRVs).

The Class II ambient air quality standards include the NAAQS and the PSD ambient air increments that apply to all Class II areas in the United States. Class II areas are places that the air quality is important for the welfare and health of humans, animals, and vegetation. All areas of the United States, with the exception of Class I areas, are designated as Class II areas.

Class I areas are places that the air quality is of special interest and value. Class I areas include national parks, wilderness areas, and national forests. Class I area standards include ambient air increments (similar to those of class II areas, only more stringent) and AQRVs. AQRVs are such issues as visibility (light extinction) and acid deposition.

The air quality analysis was performed in accordance with the previously submitted PSD dispersion modeling protocol incorporating the ODEQ comments. The source parameters used in the preliminary dispersion modeling are summarized in the previous table.

Modeling Applicability

Air dispersion modeling has been performed for NO₂ emissions from the proposed project to compare with applicable annual modeling significance level, Class I significant impact level, NAAQS, and Class II PSD Increments.

Significance Modeling

To determine whether emissions of a pollutant are required to be modeled for comparison with the ambient air standards (refined modeling analysis), it must be determined if the emissions have a significant impact on ambient air quality. Receptor grids used for determining significance are the same as those used in the refined modeling analysis. If the maximum modeled off-site concentration is greater than the MSL, the source impact is considered significant and a refined modeling analysis must be performed. Prior to performing the refined modeling analysis, a ROI must be established. The ROI is the maximum distance from the source at which impacts greater than or equal to the applicable MSL are predicted. This ROI is then used to establish nearby sources that must be included in the refined modeling analysis. The annual MSL for NO₂ is 1.0 µg/m³. A significance modeling analysis was performed and the results were higher than 1.0 µg/m³ so a refined analysis was performed.

Refined Modeling Analysis

Pollutant emissions for which the proposed facility is considered to have a significant impact on air quality, must demonstrate that the proposed facility will not cause or significantly contribute to a violation of the NAAQS. For major PSD sources, the refined modeling analysis must demonstrate compliance with the NAAQS and PSD increments.

The NAAQS were established by the USEPA under the authority of the Clean Air Act. Primary NAAQS define levels of air quality that the USEPA deems necessary to protect public health.

Secondary NAAQS define levels of air quality that the EPA judges necessary to protect public welfare from any known, or anticipated adverse effects of a pollutant. Examples of the public welfare that are protected by the secondary NAAQS include wildlife, buildings, national monuments, vegetation, visibility and property values. The USEPA has NAAQS for six criteria pollutants: PM₁₀, SO₂, NO₂, CO, ozone, and lead. The USEPA is currently working to implement a NAAQS for particulate matter less than 2.5 microns in aerodynamic diameter (PM_{2.5}). The following table lists the NAAQS for NO₂.

TABLE V-3. Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS (µg/m ³)
NO ₂	Annual	100 ¹

NOTE: ¹ Never to be exceeded

A refined modeling analysis was performed to demonstrate that the air emissions from the proposed new facility do not cause or significantly contribute to a violation of a NAAQS or PSD increment. In demonstrating compliance with the NAAQS, all nearby significant NO₂ emitting sources (50 kilometers plus ROI) was included to the Sunoco’s new and existing NO₂ emitting sources. To comply with the PSD Increments requirements, all nearby NO₂ increment consuming sources were added to NO₂ emissions resulting from the proposed modification. Tier 1 approach was adopted in the PSD increment analysis. Tier 1 approach requires that nearby PSD increment consuming sources plus emissions from the proposed modification be modeled using their potential emissions.

Sunoco used a nearby source inventory, provided by ODEQ, that incorporated all sources located within the ROI + 50 km and that meets the 10-D criteria.

Building Downwash

The modeled emissions from the Sunoco facility were evaluated to determine if the emissions plume may become entrained in turbulent wakes, thus resulting in potentially higher ambient air impacts. These wake effects, also known as downwash, are the result of air flowing around large buildings and structures creating areas, or "zones", of turbulent airflow. The minimum stack height necessary to avoid downwash effects, known as Good Engineering Practice (GEP) stack height, is defined by the following equation.

$$H_{GEP} = H + 1.5L \text{ ----- (1)}$$

H_{GEP} = GEP stack height

H = Structure or building height

L = the lesser of the structure height or project width

This equation applies only to stacks located within 5L of a downwash structure. Stacks located more than 5L from the downwash structure are not subject to the wake effects of that structure. If more than one stack at the facility is modeled, the equation must be successively applied to each

stack. If more than one structure is modeled, the equation must also be successively applied to each structure. The building downwash determination for this modeling analysis is performed for each stack and structure using the USEPA-approved Building Profile Input Program for Prime (BPIPFRM) that is compatible with AERMOD. BPIPFRM will perform the aforementioned calculation for every 10-degree directional interval starting at 10 degrees and going clockwise to 360 (due North).

GEP Stack Height Determinations

As specified by the USEPA in Appendix W of 40 CFR 51 Section 7.2.5, no stack height credit may be given in excess of the GEP stack height for any source when determining emission limitations for compliance with the NAAQS and PSD Increments. As defined in 40 CFR 51.100, GEP stack height is the greater of 65 meters or the height determined using the equation discussed in Section 3.4. Some of the stack heights used for the dispersion modeling analysis are well below 65 meters. Therefore, the emission rates and stack heights used in the modeling analysis are appropriate for demonstrating compliance with the NAAQS and PSD Increments. Building downwash has been calculated and included in the dispersion modeling for all stacks.

Modeling Options

The modeling was conducted using the refined model AERMOD (version 07026), with the following settings:

- regulatory default model parameters, including:
 - calm correction
 - buoyancy induced dispersion
 - stack-tip downwash
 - direction specific building downwash
 - final plume rise
 - default wind profile coefficients
 - default vertical potential temperature gradients
 - five years of meteorological data (2001 – 2005) pre-qualified by ODEQ consisting of:
 - Surface Air data from Bixby Mesonet Surface Station and the Tulsa/Lloyd Jones Map (Station ID# 723564), and
 - Upper Air from Norman, OK (Station ID # 03948).

Based on land use classifications from United States Geological Survey (USGS) topographical maps, the majority (i.e., > 50%) of the land surrounding the Tulsa facility can be classified urban. Therefore, the urban dispersion coefficients were used. Elevated terrain is used in the modeling analysis to accurately account for the geographical terrain features surrounding the proposed site. The terrain elevations are established using digital elevation model (DEM) files from the USGS.

Ambient Air (Fenceline) Boundary

The NAAQS and ambient air increments apply to air that is considered ambient. Ambient air quality is air outside of buildings that is accessible by the public. In most cases, ambient air boundaries are delineated based on the location of a fence or other significant physical barrier that restricts public access. However, in some instances no physical barriers exist and it is impractical to install such a barrier. Active barriers may be used as a last resort to prevent public access in these areas. Active barriers are identified as a combination of surveillance, signs, and security measures that will discourage unauthorized access

Receptor Grid

AERMOD model concentrations may be estimated at discrete receptor locations. The discrete Cartesian receptor grid is designed to identify maximum predicted impacts due to the proposed facility. The following receptor systems were used:

- A fenceline receptor system with receptors placed along the fenceline at an interval of 50 meters;
- A fine Cartesian grid extending 3 kilometers from the site in every direction with receptors located at an interval distance of 100 meters;
- A coarse Cartesian grid extending approximately 7 kilometers from the site with receptors located at an interval distance of 500 meters, and
- Additional coarse Cartesian grid extending approximately 15 kilometers from the site with receptors located at an interval distance of 1.0 kilometer,

Meteorological and Terrain Data

The dispersion modeling analysis was performed using five years (2001- 2005) of upper and surface air prequalified meteorological data provided by the ODEQ. The surface air data was collected at the Bixby Mesonet weather monitoring station and the Tulsa/Lloyd Jones Map, OK (Station ID# 723564). The upper air data was collected from the Norman University, OK weather station (Station ID # 03948). Terrain elevations consisting 26 quadrangles of the USGS 7.5 minute Digital Elevation Model (DEM) terrain data were also utilized.

Background Concentrations

The existing ambient air concentrations must be accounted for when demonstrating compliance with the NAAQS. The existing ambient air concentrations (often referred to as background concentrations) are often estimated using ambient air monitoring data from the air basin that the proposed site is located. This method of estimating the background concentration is conservative because it accounts for the existing air pollutant concentrations (including existing stationary source impacts). Therefore, refined modeling analyses that use the ambient air monitoring data as background concentrations are double counting the actual emissions from existing facilities. For this modeling analysis, the background concentration is estimated based on information

provided by the ODEQ. The background concentration used in this modeling analysis is shown in the following table.

TABLE V-5. Tulsa NO₂ Background Concentration (2006 Annual Mean)

Pollutant	Averaging Period	Station ID	Concentration (µg/m³)
NO ₂	Annual	401431127	20.7

Nearby Sources

Facilities that must demonstrate compliance with the NAAQS must also include any sources that are within the ROI plus 50 kilometers, also known as the area of significant influence (ASI). The ROI is defined as the farthest distance that the modeled facility has an impact equal to or greater than the applicable MSL. The ROI defined in the preliminary evaluation is approximately 0.7 kilometers from the facility's epicenter. Sources within the defined ROI plus 50 kilometers were included in the modeling.

DISPERSION MODELING RESULTS

Significance Modeling Results

The proposed NO₂ emissions were modeled and compared to the MSL. The preliminary analysis utilized Tier II NO₂/NO_x ambient ratio method (ARM) listed in Appendix W of the EPA's Guideline for Air Quality Model to assess the significant impacts of NO₂. The initial modeling evaluation indicated that the ground level impact is above the NO₂ MSL (1.0 µg/m³).

Since the impact from the proposed project is greater than the MSLs for NO₂, full impact modeling was performed that included nearby sources identified by the ODEQ as significant sources of NO₂ for NAAQS and PSD increment consumption. The NAAQS and PSD increments impacts were evaluated separately. The emissions data used in the NAAQS evaluation includes the proposed and existing NO₂ emission points (PTE basis) at the Sunoco facility and other nearby significant sources as provided by ODEQ. The PSD increment evaluation was based on potential emissions from the proposed project plus NO₂ emissions from other PSD increment consuming sources identified by ODEQ within the nearby sources inventory.

The proposed NO₂ emissions were modeled and compared to the Class I Significant Impact Level (SIL). If a significant impact analysis indicates impacts less than the proposed Class I Significant Impact Level (SIL) of 0.1 µg/m³, then a full Class I increment analysis is not needed. The closest two Class I areas are Upper Buffalo Wilderness (230 km) and Caney Creek Wilderness (250 km). Given the amount of emissions and the distance to the Class I areas, the source was not expected to exceed the SIL. Considering the costs and time associated with a CALPUFF impact analysis, an analysis was first performed utilizing AERMOD (which has an effective range of 50 km). If an AERMOD analysis at 50 km or less indicates impacts less than the SIL, then a CALPUFF analysis is not necessary. The AERMOD analysis indicated impacts of less than 0.04 µg/m³ (less than half of the SIL) at a distance of 5 km in the directions of Upper Buffalo Wilderness and Caney Creek Wilderness, the two closest Class I areas. The impacts at Upper

Buffalo Wilderness (230 km) and Caney Creek Wilderness (250 km) would be significantly below the SIL. Therefore, the proposed source does not cause or contribute to a NO_x Class I increment violation.

TABLE V-6. Summary of Class I Significant Impact Analysis Results for NO₂ in µg/m³

Pollutant	Averaging Period	Class I Significant Impact Level (µg/m ³)	Modeled Concentration ¹ (µg/m ³)	Comparison to Class I SIL (< or >)
NO ₂	Annual	0.1	0.04	<

¹ Concentration at 5 km from the facility.

NAAQS and PSD Increment

As presented in the following tables, the total impacts of NO₂ are below the applicable NAAQS and PSD Increments. The total impacts include the impacts from proposed and existing NO₂ emission points at the Sunoco, Tulsa facility and other nearby sources plus existing background concentration.

TABLE V-7. Summary of Dispersion Modeling Analysis Results for NO₂ in µg/m³

Impact on NAAQS:

Pollutant	Averaging Period	Year ¹	Modeled Concentration ²	Background Concentration	Total Concentration	NAAQS
NO ₂ ⁴	Annual ³	2001	73.69	20.7	94.39	100

PSD Increment Consumption:

Pollutant	Averaging Period	Year ¹	Modeled Concentration ²	Background Concentration	Total Concentration	Class II PSD Allowable Increment
NO ₂ ⁴	Annual ³	2001	11.06	NA	11.06	25

NOTES:

- [1] Year shown is worst case scenario
- [2] Includes any nearby source contributions provided by the OK DEQ.
- [3] Concentration shown is "high-first-high"
- [4] Reported as NO₂ using Tier II NO₂/NO_x ambient ratio method

The above results demonstrate that the proposed Diesel Upgrade project at the Sunoco, Tulsa Refinery will comply with the NO₂ NAAQS, and PSD Increments.

ADDITIONAL IMPACTS ANALYSIS

The additional impact analyses required pursuant to 40 CFR 52.21(o) are:

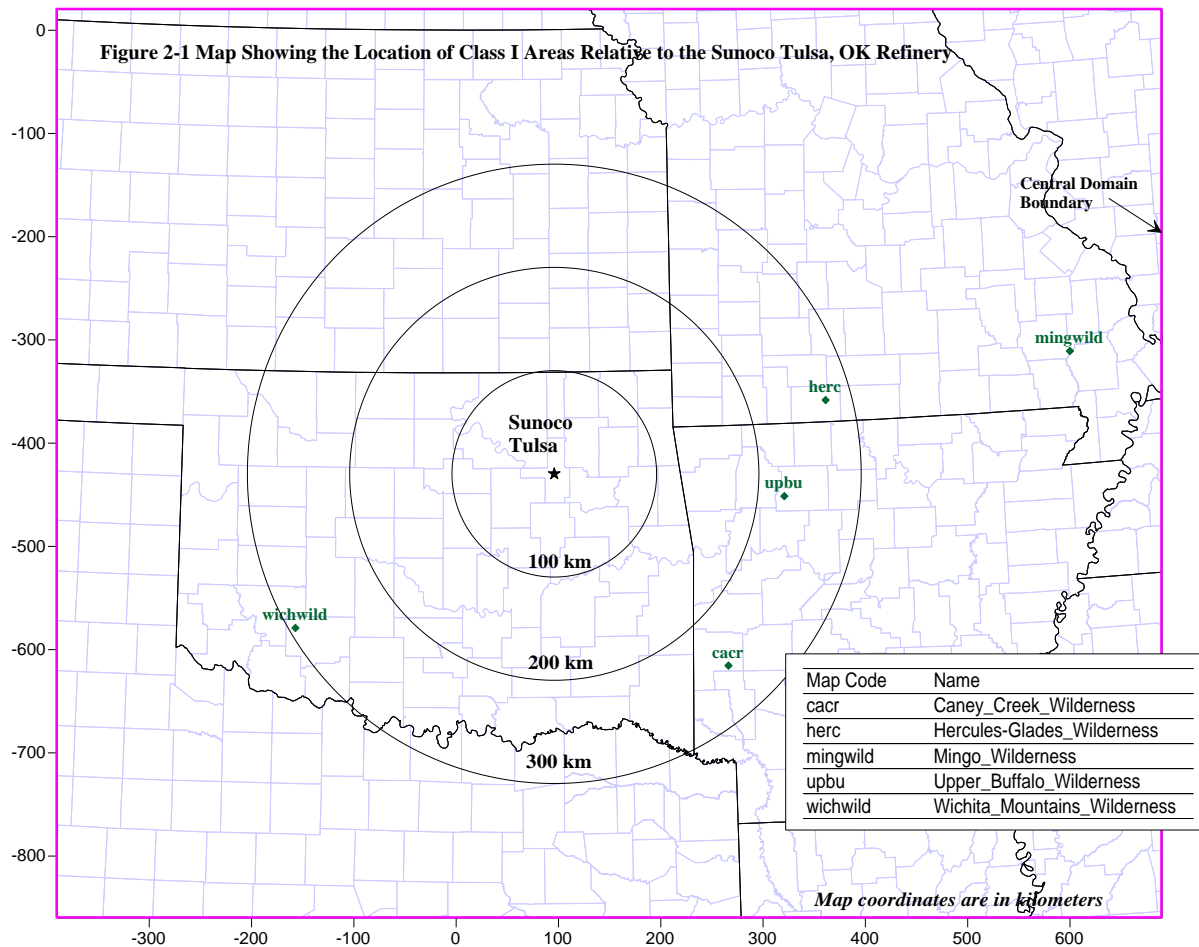
- Visibility impacts in Class I areas within 300 km
- Visibility impacts in Class II areas
- Impacts on soils and vegetation that would result from the modification
- Impacts on endangered species
- Socioeconomic analysis

The air quality modeling projections performed and presented in the previous Section have demonstrated that the proposed modification will not cause or contribute to an exceedance of the applicable National Ambient Air Quality Standard (NAAQS), or PSD Class II increments. The same can be said for any other anticipated effects that the proposed modification might have upon the surrounding areas of the Sunoco refinery. Although the source impact analysis is a quantitative, mathematical determination evaluated in relative numerical terms, other impact analyses are generally more qualitative and descriptive in nature. The following sections summarize those additional considerations and demonstrate in each case that the proposed modification will produce no adverse effects.

Visibility Impact Analysis in Class I Areas

The Clean Air Act Amendments require evaluation of new emission sources to determine potential impact on visibility in Class I areas. Mandatory Class I areas include international parks, national wilderness areas, national memorial parks and other areas re-designated to Class I areas by the state.

There are four Class I areas within 300 km of the refinery, as shown in the following figure. The closest two Class I areas are Upper Buffalo Wilderness (230 km) and Caney Creek Wilderness (250 km). Using the screening guidance from the Federal Land Manager (FLM), an assessment of emissions using the 10D screening indicates that no detailed Class I analysis for visibility will be required. Specifically, if the sum of annual potential emissions of NO_x , PM_{10} , and SO_2 is less than 10D (where D is the distance in km to the Class I area), no detailed analysis is required. The sum of $\text{NO}_2/\text{SO}_2/\text{PM}_{10}$ emissions from the proposed project totals 138.03 TPY [121.77+ 2.81 + 13.45]; the Class I areas would have to be within 13.8 km of the source in order to trigger detailed analysis.



As presented above, since the emission screening method indicates that the source strength is low and distance to Class I areas is great, no impacts to visibility in nearby Class I areas is anticipated. Therefore no additional detailed visibility impact analysis is required.

Visibility Impact Analysis in Class II Areas

An assessment of potential impacts to Class II areas was conducted according to ODEQ guidance to assess possible impacts on visibility in nearby sensitive areas. The closest sensitive area to the Sunoco Tulsa Refinery is the Deep Fork Wildlife Refuge, near Okmulgee, OK. This sensitive area is between approximately 40 and 50 km south of the facility.

The potential Class II visibility impacts were assessed in the closest nearby sensitive area (Deep Fork Wildlife Refuge) using the EPA Visibility Screening Model - VISCREEN. This screening tool was applied using twice the default Class I screening thresholds, according to ODEQ guidance for impact assessment in Class II areas. The results of this screening indicated that predicted visibility impacts were less than the applicable impact thresholds for plume contrast and perceptibility.

Impacts on Soils and Vegetation

Impacts on soils and vegetation apply only to those areas in which there is vegetation of significant commercial or recreational value. There are not vegetation or soil types in the Sunoco refinery area, which would be harmed by concentrations of criteria pollutants below the national ambient air quality standards.

Impacts on Endangered Species

Because the emission of NO₂ from proposed project will not impact the NAAQS, no impacts are anticipated to occur to any listed endangered or threatened species.

Socioeconomic Analysis

The proposed construction will have no measurable affect on the community surrounding the refinery.

SECTION VI. TRIVIAL ACTIVITIES

ODEQ has established a list of activities in OAC 252:100 Appendix J that are considered inconsequential with regards to air emissions. Unless the activity is subject to an applicable State or Federal requirement, these activities are not specifically identified in the permit. However, the standard conditions of the permit specify that the facility is allowed to operate these activities without special conditions.

SECTION VII. INSIGNIFICANT ACTIVITIES

The insignificant activity listed in OAC 252:100-8, Appendix I, applicable to this project is listed below.

1. Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. The amine tank meets this criteria.

SECTION VIII. OKLAHOMA AIR POLLUTION CONTROL RULES

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

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

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in “attainment” of these standards.

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

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
This subchapter sets forth permit application fees and the substantive requirements for operating permits required by 40 CFR Part 70 sources. Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the “Insignificant Activities” or “Trivial Activities” thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

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

Emission limitations and operational requirements necessary to assure compliance with all applicable requirements for all sources are taken from the construction permit application, or developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
In the event of any release that results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. In addition, if the owner or operator wishes to be considered for the exemption established in 252:100-9-3.3, a Demonstration of Cause must be submitted within 30 calendar days after the occurrence has ended.

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

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Appendix C specifies a PM emission limitation of 0.60 lbs/MMBTU for all equipment at this facility with a heat input rating of 10 Million BTU per hour (MMBTUH) or less and sets a most restrictive rating of 0.10

lb/MMBTU for the largest equipment. Fuel-burning equipment is defined in OAC 252:100-1 as “combustion devices used to convert fuel or wastes to usable heat or power.” Thus, the fuel-burning equipment listed in this project, Boilers 3, 4, 7, 8, and 9 and Heaters B4101 and B4102, are subject to the requirements of this subchapter. Gas-fired fuel-burning equipment at the facility burns either RFG or commercial grade natural gas (or its equal). RFG is a mixture of various process unit light gases that contain hydrogen (non-particle emitting) and methane through butane light hydrocarbons. RFG is a dry gas, free of liquid particles due to liquid knockout collection drums prior to final fuel end use. Dry gas is recognized by EPA to be at least as clean burning, as to particulates, as commercial grade natural gas. Since AP-42 has no distinct factor for dry gas mixtures the following demonstrations are based on the natural gas (methane) factors. Table 1.4-2 of AP-42 lists the total PM emission factor for equipment burning natural gas to be 7.6 lbs/10⁶ft³. If we make the conservatively high assumption that PM emissions are related only to volume and that heat content has no effect, then the gas with the highest PM emission in units of pounds per MMBtu will be the gas with the lowest heating value. The lowest heating value found is 584 Btu/DSCF, implying emissions of 0.013 lbs PM/MMBtu. This conservative result is still a factor of 10 below the 0.10 lb/MMBtu most restrictive allowance identified in the introductory paragraph for any equipment at the facility.

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 or refinery fuel gas there is very little possibility of exceeding these 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 originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Under normal operating conditions, this facility has negligible potential to violate this requirement; therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) (Applicable)
Part 2 concerns ambient concentrations of SO₂ and H₂S for new and existing equipment. Emissions of sulfur compounds from any existing facility shall not result in an ambient air concentration outside the facility property line greater than those specified at §31-7(a) as to SO₂ and §31-7(b) as to H₂S. There are no significant H₂S emission points.

The facility claims to be in compliance based on AERMOD ambient air quality modeling submitted to the Air Quality Division in February 2003. AERMOD modeling, using building and stack downwash features, was applied to area-wide ambient air receptors. Actual daily emissions from Sunoco were modeled with concurrent meteorology to reflect actual impacts.

Additional AERMOD modeling was applied to area-wide ambient air receptors. Actual daily emissions from Sunoco were modeled with coincident meteorology from the past five years.

Exceedances were shown in a small area immediately east of Sunoco. Modeled concentrations were compared to monitored concentrations from EPA/DEQ monitoring sites 501, 175, and 235, showing that AERMOD modeled impacts at the monitors exceeded the actual measured concentrations. Sunoco's consultant (ERM) refers to these as "false exceedances" of the 24-hr $130 \mu\text{g}/\text{m}^3$ standard.

ERM and Sunoco concluded that because the AERMOD model over-predicts ambient concentrations, modeling data alone cannot be relied upon to demonstrate ongoing compliance. To prevent exceedances (shown by EPA/DEQ monitoring) and to determine compliance with the ambient air quality standards of §31-7(a), Sunoco will conduct monitoring of the ambient air quality and take action as described below: The knowledge of what significant variables affect refinery SO_2 emissions played a major role in determining that the actions described in the following will be adequate to keep the facility's SO_2 emissions in compliance.

1. Monitor SO_2 ambient air concentrations measured at the east perimeter of the refinery. This will consist of a portable instrument operated for a period of 1 hour during each 12-hour period (2 times per day). Compliance with the 24-hour concentration limit will be presumed as long as all readings are below the detection limits of 0.1 ppmv.

2. For any hourly measurement of 0.1 ppmv or greater, Sunoco will continue hourly monitoring until levels are below 0.1 ppmv. At any time that 6 consecutive hourly measurements exceed 0.1 ppmv, Sunoco will take actions to reduce SO_2 emissions to less than the target value.

3. Monitor and record meteorological data from measurement equipment located at the refinery.

4. Sunoco will submit a report to the Division Director by the 30th day following the end of each calendar quarter that lists all monitoring data, meteorological data, and actions taken to reduce SO_x emissions in the event of 6 consecutive hourly readings above 0.1 ppmv.

5. Excess Emissions will be reported pursuant to the requirements of OAC 252:100-9.

Part 5 contains new equipment standards. As used here, "new" refers to any equipment constructed or modified after July 1, 1972, with certain exceptions, as defined in §31-2.

Paragraph 31-25(a)(1) covers gas-fired fuel-burning equipment. The equipment listed below is presumed in compliance because this equipment burns only commercial pipeline quality natural gas or gas that is equal or better or for B4101 and B4102 NSPS Subpart J compliant gas.

1. #7 Boiler
2. #8 Boiler
3. #9 Boiler
4. Heater B4101
5. Heater B4102

Section 31-26 (Petroleum and natural gas processes)

As defined in §31-2, "petroleum and natural gas processes includes equipment used in processing crude and/or natural gas into refined products and includes catalytic cracking units, catalytic reforming units, and many others. This regulation requires that H_2S from the petroleum

process equipment be removed from the exhaust stream or oxidized to SO₂. An SRU shall have the sulfur reduction efficiency required in 252.100-31-26 (a)(2)(D) which is 94.1% for a 20.1 LTPD SRU. The proposed SRU/TGTU/Incinerator in the Diesel Upgrade Project will exceed this requirement.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]

This subchapter limits new fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.20 lbs of NO_x per MMBTU, three-hour average for gas-fired equipment, 0.30 lbs/MMBTU for liquid-fired equipment, and 0.70 lbs/MMBTU for solid fuel-fired equipment. Most of the fuel-burning equipment at this facility is either too small or was constructed, rebuilt, or modified before the effective date of February 14, 1972 for “new” equipment. The following table indicates the compliance status of affected units.

Equipment	MMBTUH	Emission factor and source
#7 Boiler	150	0.20 lb/MMBTU, stack test of identical boiler #9
#8 Boiler	150	0.20 lb/MMBTU, stack test of identical boiler #9
#9 Boiler	150	0.20 lb/MMBTU, stack test
#2 Plat PH-5	52	0.15 lb/MMBTU, manufacturer’s data.
Coker B-1	60	0.09 lb/MMBtu, manufacturer’s data, 0.06 lb/MMBTU per 7/22/92 stack test.
MEK H-101	81	0.15 lb/MMBtu, manufacturer’s data.
DHT Heater B4102	53.7	0.03 lb/MMBtu, manufacturer’s data

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]

The project does not involve the installation or modification of any of the following equipment: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit. The facility is not located in, nor impacts, a nonattainment area.

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

Part 3 requires storage tanks constructed after December 28, 1974 with a capacity of 40,000 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to either be operated as a pressure vessel or be equipped with internal/external floating roofs or vapor recovery devices. The two new tanks for this project are exempt because they store liquids with a vapor pressure less than 1.5 psia.

The following tanks will store products from the DHT project. All of these tanks were constructed before the applicability date of any rules and contain liquids with vapor pressure below any of the thresholds necessary to make the tanks subject to any state rules affecting “existing” tanks.

EU	Point ID	BBL
Tk9	Tk9	7000
Tk10	Tk10	7000
15946	Tk217	7000

EU	Point ID	BBL
6377	Tk404	72273
6378	Tk405	72443
13578	Tk406	71526
6379	Tk407	71526

EU	Point ID	BBL
13568	Tk218	7000
6371	Tk323	7000

Part 3 regulates loading facilities. The following loading racks handle products from the DHT project but are not subject to OAC 252:100-37-16 because the units load VOCs with vapor pressures less than 1.5 pounds per square inch, per §37-4(a).

EU	Equipment Point ID	Installed Date
NA	Diesel Rail Loading Rack	1986
NA	Diesel Truck Loading Rack (At Truck Loading Dock)	

Section 37-36 requires fuel-burning equipment to be operated and maintained so as to minimize VOC emissions. Temperature and available air must be sufficient to provide essentially complete combustion. Refinery fuel gas combustion devices are designed to provide essentially complete combustion of organic materials.

Section 37-37 regulates water separators that receive water containing more than 200 gallons per day of VOC. Any new or existing waste water systems at the refinery are subject to NSPS Subpart QQQ, which contains standards more stringent than Part 7.

Section 37-38 sets standards for all rotating pumps or compressors handling VOC, but §37-38(b) exempts all pumps and compressors subject to NSPS Subparts VV, GGG, or KKK from this requirement. The facility’s pumps and compressors are subject to 40 CFR 60 Subparts VV or GGG and are thus exempt.

OAC 252:100-39 (VOC in Non-Attainment and Former Nonattainment Areas) [Applicable]

Section 39-15 (Petroleum Refinery Equipment Leaks) EPA test Method 21 is specified for detecting equipment leaks. VOCs with vapor pressures less than 0.0435 psia are exempt. Components covered by this section include, but are not limited to, pumping seals, compressor seals, seal oil degassing vents, pipeline valves, flanges and other connections, pressure relief devices, process drains, and open-ended pipes. All such components are tested in a monitoring program per 15(f); actions and repairs are conducted per 15(c); records are kept per 15(g); quarterly reports are made per 15(h); and monitoring logs are retained on-site for least two years.

Section 39-16 (Petroleum refinery process unit turnaround) Vented organic material must either be controlled per 39-16(b)(1) & (2) or exempted per 39-16(b)(4). Requirements for contents of the 15-day notification are listed in 39-16(b)(3). Sunoco has provided the appropriate notices for past turnarounds and is in compliance based on standard unit turnaround practices that meet requirements.

Section 39-18 (Petroleum refinery effluent water separators) The API separator will not process more than 200 gallons per day of these streams or will be sealed.

Section 39-30 (Petroleum liquid storage in vessels with external floating roofs) Storage vessels Tk307 and Tk779 are exempt per 39-30(b)(4) because they are subject to 40 CFR Part 63 Subpart CC.

Section 39-41 (Storage, loading and transport/delivery of VOCs)

Tanks Tk432 and Tk435 were previously associated with EUG 26 which was regulated through 39-41. Tank are exempt from 39-41 because new contents have a vapor pressure less than 1.5 psia.

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

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
 This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

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

OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not in source category
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39-43	Graphic Arts	not in source category
OAC 252:100-39-44	Tire Mfg.	not in source category
OAC 252:100-39-45	Dry Cleaning	not in source category
OAC 252:100-39-46	Parts Coating	not in source category
OAC 252:100-39-47	Aerospace Coating	not in source category
OAC 252:100-39-49	Fiberglass Mfg.	not in source category
OAC 252:100-47	MSW Landfills	not in source category

SECTION IX. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
 Sunoco is a major PSD source since it is on the list of 26 source categories and has emissions of at least one criteria pollutant that exceeds 100 TPY. The PSD requirements for this modification are addressed in the “PSD Review” section. Any future increases of emissions must be evaluated for PSD if they exceed a significance level.

NSPS, 40 CFR Part 60 [Subparts A, J, GGGa, and QQQ Applicable to this Project]
 The following paragraphs are general in nature, with some reference to specific facilities. The Specific Conditions contain specific requirements under NSPS for all affected facilities.

Subpart A, General Provisions. This subpart requires the submittal of several notifications for NSPS-affected sources, which, for this project, are two new process heaters, a Sulfur Recovery Unit, and new fugitive equipment. Within 30 days after starting construction of the affected sources, the permittee must notify DEQ that construction has commenced. A notification of the actual date of initial startup of any affected source must be submitted within 15 days after such date. Initial performance tests are to be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup of the source. The permittee must notify DEQ at least 30 days prior to any initial performance test and must submit the results of the initial performance tests to DEQ. The permit will require compliance with the notification requirements set forth in Subpart A.

Subpart Db (Industrial-Commercial-Institutional Steam Generating Units for Which Construction Is Commenced After June 19, 1984)
 There are no units constructed or modified after the effective date of the standard. The following units were constructed or modified prior to the effective date of the standard.

EU	Point ID	Construction Date
106A	#3 Boiler	1954
106B	#4 Boiler	1957

Subpart J, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: Claus sulfur recovery plant, fuel gas combustion devices, and, FCCU catalyst regenerators.

Claus Sulfur Recovery Plant

For Claus sulfur recovery plants with an oxidation control system or a reduction control system followed by incineration, Subpart J limits SO₂ emissions to 250 ppmvd at 0% excess air. The new SRU is subject to this emission limit, continuous emission monitoring, and the recordkeeping and reporting requirements of this subpart. All applicable requirements have been incorporated into the permit.

Fuel Gas Combustion Devices

Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or

sulfuric acid. Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. All fuel gas combustion devices which commence construction or modification after June 11, 1973, are subject to a fuel gas H₂S limitation of 0.10 grains of H₂S/DSCF which is required to be continuously monitored and recorded. The two new process heaters (B4101 & B4102) are considered refinery fuel gas combustion devices. The two new process heaters (B4101 & B4102) are subject to Subpart J.

#2 Platformer PH-5 & PH-6 Heaters operate under an Alternative Monitoring Plan for NSPS Subpart J Fuel Gas approved May 31, 2001. However, the PH-6 heater is not subject to NSPS J because it has not been constructed/modified/reconstructed since the effective date. A request was approved in 2004 to allow boilers 7, 8, and 9 to burn absorber tower offgas, so the boilers are now subject to NSPS J and follow the same alternative monitoring plan as heaters PH-5 and PH-6.

The following units are not subject to NSPS Subpart J because they were constructed prior to the applicability date of June 11, 1973.

EU	Point ID	Construction Date
106A	#3 Boiler	1954
106B	#4 Boiler	1957

The LEU flare, EU-269 (EUG-11) is not subject to NSPS Subpart J because it does not burn refinery fuel gas except during instances of emergency fuel gas release from PRVs in the Lube Extraction Unit.

Subpart Ja (Petroleum Refineries). On May 14, 2007, U.S. EPA proposed New Source Performance Standards (NSPS) for new, modified, or reconstructed process units at petroleum refineries codified in 40 CFR 60, Subpart Ja. Only those affected facilities that begin construction, modification, or reconstruction after the date the proposed rule was published in the Federal Register would be affected by the proposed Subpart Ja standards. This project would be subject to Subpart Ja as it is proposed.

Subpart Kb (VOL Storage Vessels) applies to volatile organic liquids storage vessels for which construction, reconstruction, or modification commenced after July 23, 1984, and which have a capacity of 75 cubic meters (m³) or more. Tanks with capacity greater than or equal to 151 m³ and storing VOL with TVP less than 3.5 kPa (≈ 0.5 psia) are exempt from Kb, as are tanks with capacity greater than or equal to 75 m³ and less than 151 m³ that store VOL with TVP less than 15.0 kPa (≈ 2.2 psia). Tanks with capacity greater than or equal to 151 m³ and storing VOL with TVP equal to or greater than 5.2 kPa (≈ 0.75 psia) but less than 76.6 kPa (≈ 11.1 psia) are required to have the controls described in §60.112b(a). Tanks with capacity greater than or equal to 75 m³ and less than 151 m³ and storing VOL with TVP equal to or greater than 27.6 kPa (≈ 4.0 psia) but less than 76.6 kPa are also required to have the controls described in §60.112b(a). Tanks with TVP greater than 76.6 kPa must install the closed systems described in §60.112b(b). Tanks subject to the controls of §60.112b are subject to the testing and inspection requirements of §60.113b and the reporting and

recordkeeping requirements of §60.115b. All tanks, regardless of controls, are subject to the monitoring requirements of §60.116b. Compliance is per monitoring specified at 60.113(b), and records and reporting as specified at sections 60.115(b) and 60.116(b). Tanks in EUGs 21, 22, and 23 are affected facilities under Subpart Kb. Tank inspections are documented electronically on the Refinery Tanks Database. Electronic documentation records the date of the inspection, any defects noted, and the initials of the inspector.

The amine tank is exempt based on the vapor pressure of the VOL stored and the sour water tank is exempt because it does not store a VOL.

Subpart VV, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOMCI). Although the refinery is not an affected facility, NSPS, Subpart GGG and the refinery MACT (40 CFR 63 Subpart CC) makes extensive reference to this NSPS subpart.

Subpart VVa, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOMCI) for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Although the refinery is not an affected facility, NSPS, Subpart GGGa makes extensive reference to this NSPS subpart. All equipment in VOC service affected under this permit is subject to NSPS, Subpart GGGa or NESHAP Subpart CC.

Subpart GGG (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006) 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, 1983, and on or Before November 7, 2006 and which is located within a process unit in a petroleum refinery. Subpart GGG requires the leak detection, repair, and documentation procedures of NSPS Subpart VV. Compressors in hydrogen service (defined as serving streams more than 50% by volume hydrogen) are exempt from all requirements other than demonstrating that a stream can never be reasonably expected to contain less than 50% by volume hydrogen. Those pressure-relief devices vented to a control device (flare) are exempted from periodic monitoring requirements. Equipment subject to this subpart and compliance records are maintained on-site in an electronic database. All equipment in VOC service affected under this permit is subject to NSPS, Subpart GGG, NESHAP Subpart CC or OAC 252:100-39-15.

All Leak Detection and Repair (LDAR) reporting required by 40 CFR 60, Subpart GGG (semi-annual), and 40 CFR 63, Subpart CC (semi-annual) has been consolidated to simplify overlapping requirements, based on discretion granted to the state authorities by EPA. All LDAR reporting is included in the MACT Semi-annual report covering all monitoring required from January 1st through June 30th and July 1st through December 31st. Reports are due 60 days after the end of each six month period per 40 CFR 63.654(g).

Subpart GGGa (Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006). On November 16, 2007, EPA published Subpart GGGa for affected facilities located in petroleum refineries that begin construction, modification, or reconstruction after November 7, 2006. The subpart establishes emission standards for monitoring, detection and repair of

equipment leaks in petroleum refineries similar to NSPS Subpart GGG, however there are some differences and new requirements in NSPS Subpart GGGa.

The primary updates include a lowered leak definitions for pumps and valves; the addition of recordkeeping requirements for all monitored equipment; and the addition of calibration drift assessment.

Certain new components associated with the Diesel Upgrade Project will be subject to the equipment leak standards. These components will be included in the refinery's leak detection and repair program.

Subpart QQQ (VOC Emissions from Petroleum Refinery Wastewater Systems) applies to individual drain systems, oil-water separators, and aggregate facilities located in petroleum refineries and for which construction, reconstruction, or modification commenced after May 4, 1987. All existing wastewater systems were constructed or modified prior to the effective date of the standard. A new oil-water separator with drain systems will be constructed as part of this project and they will be subject to Subpart QQQ. This project will involve physical changes to individual drain systems in the form of new process drains and junction boxes. New drains installed as part of this project must be equipped with water seal controls and the applicant must comply with the monitoring, testing, recordkeeping, and reporting requirements of Subpart QQQ. All applicable requirements have been incorporated into the permit.

NESHAP, 40 CFR Part 61

[Subparts M and FF Applicable]

Subpart M (Asbestos) Molded or wet-applied friable asbestos insulation installation or reinstallation is prohibited per 61.148. The most likely activity that might be affected is the renovation or demolition of structures or equipment containing asbestos. Rules concerning such activities are found in §§60.145 and 60.150.

Subpart FF (Benzene Waste Operations) Affected sources are benzene-containing waste streams, as identified in EUG 12 for the wastewater processing system. Numerous standards apply to tanks, impoundments, and other activities if the total annual benzene (TAB) quantity exceeds 10 megagrams. Test methods and procedures used in calculating the TAB are found in §61.355, paragraphs (a) through (c). Because the refinery has TAB less than 10 Mg, it is subject to only the recordkeeping, reporting, and testing requirements found in §§61.355, 356, and 357.

NESHAP, 40 CFR Part 63

[Subparts CC and UUU are Applicable to this Project]

The following paragraphs are general in nature, with some reference to specific facilities. The Specific Conditions contain specific requirements under NESHAP for all Sunoco affected facilities.

Subpart R (Gasoline Distribution Facilities {Bulk Gasoline Terminals and Pipeline Breakout Stations})

The refinery has a gasoline terminal that is subject to NESHAP MACT Subpart CC which requires compliance with some provisions of this subpart.

Subpart Q (Industrial Process Cooling Towers)

The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources. The refinery ceased the use of chromium-based treatment before this MACT was issued.

Subpart CC (Petroleum Refineries)

Affected facilities include process vents, storage vessels, wastewater streams and treatment, equipment leaks, gasoline loading racks, marine vessel loading systems, and pipeline breakout stations. Of the facilities named in CC, storage tanks, equipment leaks, process vents, wastewater streams and treatment, and a gasoline loading rack are affected facilities at Sunoco.

Storage tanks

Existing storage tanks with HAP concentrations above 4%_w and which have vapor pressures above 1.5 psia are required to implement controls identical to NSPS Subpart Kb. Tk 307 and Tk779 (EUG19) are Group 1 Storage Vessels as defined in 63.641 and are to be controlled and monitored per 63.646. Reports and records required for these tanks are found at 63.654. General Provisions for startup/shutdown/malfunction (SSM) plans, as defined at 63.641, are found at 40 CFR 63.6(e)(3). Semi-annual and immediate reporting requirements are listed at 63.10(d)(5). Electronic documentation, including the date of the inspection, any defects noted, and the initials of the inspector, is maintained on-site in the facility's "Refinery Tanks Database."

EUG 20 lists Group 2 Storage Vessels as defined at 63.641. Subparagraph 63.654(i)(1)(iv) requires a determination of Group 2 Tanks. The facility maintains a list of tanks that do not contain any HAPs and are not Group 2 Tanks per 63.640(a)(2).

Process Vents

Any refinery unit process vent with greater than 20 ppmv HAPs and which emits more than 33 kg/day of VOC is subject to control requirements. Subpart CC requires affected vents to be equipped with 98% efficient controls, be vented to a flare, be vented to a combustion unit firebox, or be reduced to 20 ppmv HAP or less. Group 1 Process vents include the Coker Flare (EUG 14). Group 1 Process Vents are vents for which the total organic HAP concentration is greater than or equal to 20 ppmv, and whose total VOC emissions are greater than or equal to 33 kg per day (75 lbs/day).

Equipment Leaks

Portions of the project contain Hazardous Air Pollutant (HAP) fugitive equipment component sources that exist in the refinery. Two compliance options are given at 63.648, consisting of a modified 40 CFR 63, Subpart H method, and a modified 40 CFR 60, Subpart VV method. The Sunoco Refinery currently chooses to follow the Subpart VV option. The 40 CFR 63 Subpart CC modifications to Subpart VV are primarily in applicability and component exemptions. Applicability is limited to components that contain equal to or more than 5% by weight HAP. Exemptions in addition to Subpart VV include wastewater system drains, storage tank sample valves, and tank mixers. Also, reciprocating pumps in light liquid service and reciprocating compressors are exempt from 60.482 if recasting the distance pieces or new equipment is required. Subpart VV requires, among other things, leak detection and repair at valves in

gas/vapor and light liquid service, and offers three options for such valves. The first is the main standard at 40 CFR 60.482-7, which requires monthly monitoring unless the valve shows no leaks after two successive months after which the valve may be monitored quarterly until it indicates leakage. The second option is given at 60.483-1, in which valves are tested initially, and then annually or as requested by DEQ, and the percentage of leaking valves is not allowed to exceed 2%. The third option is given at 60.483-2, in which good leak performance leads to skip periods of monitoring that leads to annual monitoring so long as the quantity of leaking components vs. total number of components remains below 2%. The use of either of the second two options requires prior notification to DEQ. This facility currently follows the base procedures given at 60.482-7, but requests alternative scenario status for the other two options since they represent another form of compliance measurement, and because they require notification to DEQ. Whether these scenarios will be used or not depends on the facility's analysis of the benefits of invoking them. At the present time these options are moot because OAC 252:100-39-15 requires quarterly monitoring of valves. If Section 39-15 is modified in the future to provide reduced monitoring after periods of continuous compliance, the facility will select the compliance option described in §63.648(a)(2). The facility will also comply with the leak monitoring requirements in the Federal Consent Decree.

All Leak Detection and Repair (LDAR) reporting required by 40 CFR 60 Subpart GGGa (semi-annual), and 40 CFR 63 Subpart CC (semi-annual) has been consolidated to simplify overlapping requirements. All LDAR reporting is included in the MACT semi-annual report covering all monitoring required from January 1st through June 30th and July 1st through December 31st. Reports are due 60 days after the end of each six month period per 40 CFR 63.654(g).

Wastewater Streams and Treatment

Requirements for the wastewater system are defined at 63.647 as equivalent to the provisions of 40 CFR 61, Subpart FF. Recordkeeping, reporting, and monitoring is also defined at 63.654 to be what is required at 61.356 and 61.357. Compliance with 40 CFR 61, Subpart FF indicates compliance with 40 CFR 63, Subpart CC.

Subpart UUU (Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units). The new SRU is subject to this subpart. The subpart affects the following parts of this project:

1. The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants, that are associated with sulfur recovery; and
2. Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart.

Sulfur Recovery Units

Sulfur recovery units subject to the NSPS, Subpart J, SO₂ emission limit (≤ 250 ppmvd @ 0% excess air) must comply with the NSPS Subpart J, SO₂ emission limit. The new SRU is subject to NSPS, Subpart J and will meet all applicable requirements of this subpart and

NSPS, Subpart J. The SRU will use a CEM to show compliance with this standard on a 12-hour rolling average basis.

Bypass Lines

The SRU has bypass lines that are vented to the flare system. Bypass lines must meet the work practice standards in Table 36 and continuous compliance requirements of Table 39 of this subpart.

An operation, maintenance, and monitoring plans is required to be prepared and submitted for the SRU and Bypass Lines. The facility will submit the plan with their initial compliance demonstration and their startup, shutdown, and malfunction plan. All applicable requirements of this subpart have been incorporated into the permit.

Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters) In March, 2007, the EPA filed a motion to vacate and remand this rule back to the agency. The rule was vacated by court order, subject to appeal, on June 8, 2007. No appeals were made and the rule was vacated on July 30, 2007. Existing and new small gaseous fuel boilers and process heaters (less than 10 MMBtu/hr heat rating) were not subject to any standards, recordkeeping, or notifications under Subpart DDDDD.

EPA is planning on issuing guidance (or a rule) on what actions applicants and permitting authorities should take regarding MACT determinations under either Section 112(g) or Section 112(j) for sources that were affected sources under Subpart DDDDD and other vacated MACTs. It is expected that the guidance (or rule) will establish a new timeline for submission of section 112(j) applications for vacated MACT standards. At this time, AQD has determined that a 112(j) determination is not needed for sources potentially subject to a vacated MACT, including Subpart DDDDD. This permit may be reopened to address Section 112(j) when necessary. Based on the original rule applicability, Boilers 3, 4, 7, 8, and 9 and DHT Heaters B4101 and B4102 are subject for gaseous fired units.

Compliance Assurance Monitoring, 40 CFR Part 64

[Not Applicable at this Time]

This part applies to any pollutant-specific emission unit at a major source that is required to obtain an operating permit, for any application for an initial operating permit submitted after April 18, 1998, that addresses “large emissions units,” or any application that addresses “large emissions units” as a significant modification to an operating permit, or for any application for renewal of an operating permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY or 10/25 TPY of a HAP

No equipment from the DHT project is subject to CAM.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
Toxic and flammable substances subject to this regulation are present in the facility in quantities greater than the threshold quantities. A Risk Management Plan was submitted to EPA on June 1, 1999, and resubmitted as required by rule.

Stratospheric Ozone Protection, 40 CFR Part 82 [Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

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

This facility does not utilize any Class I & II substances in its manufacturing processes.

SECTION X. 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 "DEQ Notice of Filing a Tier II Application" in the *Tulsa World*, a daily newspaper of general circulation in Tulsa County on January 13, 2008. The notice said that the application was available for public review at the AQD office in Tulsa or OKC. A "Notice of Tier II Draft Permit" was published in the *Tulsa World*, a daily newspaper of general circulation in Tulsa County on March 16, 2008. A copy of the draft was available at the DEQ Regional Office at Tulsa and the AQD office in Oklahoma City, as well as on the DEQ website. The facility is not located within 50 miles of any other state border. The applicant requested concurrent Public and EPA review. The permit was forwarded to EPA for a 45 day review

period. There were no comments from the public. Sunoco had minor comments to fix typographical errors. The errors were fixed and did not require additional public or EPA review. There were no comments from EPA during the 45 day review period.

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

Fee Paid

Modification of a Part 70 source construction permit fee of \$1,500.

SECTION XI. SUMMARY

This facility was constructed as described in the application. There are no active Air Quality compliance or enforcement issues that would affect the issuance of this permit. Issuance of the construction permit is recommended.

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

**SUNOCO, Inc. (R&M)
Tulsa Refinery**

Permit Number 98-014-C (M-14) PSD

The permittee is authorized to construct in conformity with the revised specifications submitted to Air Quality on December 4, 2007, many supplemental data packages submitted, and with various reviews of the interim work product provided by the applicant. The Evaluation Memorandum dated May 23, 2008, 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. Only those portions of the Specific Conditions directly affected are addressed. All other portions of the Specific Conditions are unaffected by this modification and continue as stated in the underlying Part 70 permit.

1. Points of emission, emission limitations, and standards [OAC 252:100-8-6(a)]

A. Process Heaters

Process Heaters	Emissions										
	MMBtu/hr	NOx		VOC		PM ₁₀		CO		SO ₂	
		lb/MMBtu*	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/MMBtu**	TPY
DHT Heater (B4101)	44.0	0.03	5.78	0.43	1.25	0.59	1.72	6.52	19.05	0.03	2.42
DHT Heater (B4102)	53.7	0.03	7.06	0.53	1.52	0.72	2.10	7.96	23.24	0.03	2.95

*Short term NOx limitation per BACT based on average of three 1-hour performance test runs

**Short term SOx limitation based on conversion of NSPS Subpart J limitation of 160 ppmv H₂S to SO₂. Limit based on 3-hr averaging period. 160ppmvH₂S * 64lb SO₂/lbmol / 379.4 scf/lb-mol / 820 btu/scf (HHV RFG) = 0.03 lb SO₂/mmbtu

- i. B4101 and B4102 are subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements and standards, including but not limited to: [40 CFR Part 60]
 - a. §60.104 Standards for sulfur oxides. B4101 and B4102 shall combust only pipeline grade natural gas, #2 Platformer offgas, or refinery fuel gas with a 3-hour rolling average maximum H₂S concentration of 0.1 gr/dscf (160 ppmv @ 60°F).
 - b. §60.105 Monitoring of emissions and operations. A continuous monitoring system shall be operated and maintained to record H₂S content of the fuel gas.
 - c. §60.106 Test methods and procedures
 - d. §60.107 Reporting and recordkeeping requirements
 - e. §60.108 Performance test and compliance provisions
- ii. Compliance of B4101 and B4102 with the SO₂ emission limits of Specific Condition 1.A shall be based on a 365-day rolling average fuel gas usage and H₂S content and

shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

$$\text{SO}_2, \text{TPY} = \frac{\text{MMSCFD} * \text{ppmvd H}_2\text{S} * 64 \text{ lb SO}_2/\text{lb-mole} * 365 \text{ days/year}}{2000 \text{ lb/ton} * 379.4 \text{ Scf/lb-mole}}$$

- iii. B4101 and B4102 shall be constructed with burners with NO_x emissions limited to no greater than 0.03 lb/MMBtu (HHV), average of three 1-hr performance test runs.
[OAC 252:100-8-6(a)]
- iv. Compliance of B4101 and B4102 with the NO_x, CO, and VOC annual emission limits shall be based on a 365-day rolling average fuel gas usage and heater specific (stack test) emission factors, when available, or the most current version emission factors from AP-42 Table 1.4-1 plus a 20% safety factor. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

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

where EF = Emission Factor, lb/MMBtu

- v. B4101 and B4102 shall be operated using good combustion practices to comply with the emission limitations of PM₁₀.
[OAC 252:100-8-6(a)]
- vi. Within 60 days of achieving maximum firing rate from the heaters, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall, for each heater, conduct performance testing for NO_x, CO, and VOC and furnish a written report to Air Quality documenting compliance with emission limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR Part 60:
 - a. Method 1: Sample and Velocity Traverses for Stationary Sources.
 - b. Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
 - c. Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight
 - d. Method 4: Determination of Moisture in Stack Gases.
 - e. Method 7E: Determination of Nitrogen Oxide Emissions From Stationary Sources.
 - f. Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources.
 - g. Method 18 or 25A: Determination of Volatile Organic Compounds Emissions From Stationary Sources
 - h. Method 19: F-factor Methodology

B. Sulfur Recovery Unit (SRU) / Tail Gas Treatment Unit (TGTU)

SRU	Emissions									
	NO _x		VOC		PM ₁₀		CO		SO ₂	
	lb/ MMBtu*	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	ppmv**	TPY
SRU Unit	0.14	4.4	2.41	7.03	1.62	4.73	1.00	2.93	250	15.93

*Short term NO_x limitation per BACT based on average of three 1-hour performance test runs

**Short term SO_x limitation per NSPS Subpart J based on 12-hr averaging period

- i. The SRU/TGTU is subject to 40 CFR Part 60, Subpart J and shall comply with all applicable requirements and standards, including but not limited to: [40 CFR Part 60]
 - a. §60.104(a)(1) Standards for sulfur oxides. The SRU shall combust only pipeline grade natural gas, #2 Platformer offgas, or refinery fuel gas with a 3-hour rolling average maximum H₂S concentration of 0.1 gr/dscf (160 ppmv @ 60°F).
 - b. §60.104(a)(2) Standards for sulfur oxides. The SRU (Claus sulfur recovery plant followed by an incinerator) is limited to a 12-hour rolling average maximum SO₂ concentration of 250 ppmv (dry basis) at zero percent excess air. The monitor shall include an oxygen monitor for correcting the data for excess air.
 - c. §60.105 Monitoring of emissions and operations. A continuous monitoring system shall be operated and maintained to record SO₂ as required emissions into the atmosphere (Claus unit) and record H₂S in fuel (fuel gas system).
 - d. §60.106 Test methods and procedures
 - e. §60.107 Reporting and recordkeeping requirements
 - f. §60.108 Performance test and compliance provisions

- ii. The SRU/TGTU is subject to 40 CFR Part 63, Subpart UUU and shall comply with all applicable requirements and standards, including but not limited to:[40 CFR Part 63]
 - a. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1), (b)(1, 3, 4, 5, 6, & 7), & (c)(1 & 2);
 - b. § 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
 - c. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
 - d. 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
 - e. 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
 - f. 63.1574 What notifications must I submit and when? – (a)(2) & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
 - g. 63.1575 What reports must I submit and when? – (a-h);
 - h. 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
 - i. 63.1577 What parts of the General Provisions apply to me?

- iii. Compliance of the SRU with the SO₂ emission limits of Specific Condition 1.B shall be based on the continuous monitoring system.
- iv. The SRU shall be constructed with burners with NO_x emissions limited to no greater than 0.14 lb/MMBtu (HHV), average of three 1-hr performance test runs.
[OAC 252:100-8-6(a)]
- v. Compliance of the SRU with the NO_x, CO, and VOC annual emission limits shall be based on a 365-day rolling average fuel gas usage and heater specific (stack test) emission factors, when available, or the most current version emission factors from AP-42 Table 1.4-1 plus a 20% safety factor. Compliance shall be demonstrated monthly using on-line instrumentation and calculations, when available, or the following formula:

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

where EF = Emission Factor, lb/MMBtu

- vi. The SRU shall be operated using good combustion practices to comply with the emission limitations of PM₁₀.
[OAC 252:100-8-6(a)]
- vii. Within 60 days of achieving maximum firing rate from the SRU, not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall, for each heater, conduct performance testing for NO_x, CO, SO₂ and VOC and furnish a written report to Air Quality documenting compliance with emission limitations. Performance testing by the permittee shall use the following test methods specified in 40 CFR Part 60:
 - a. Method 1: Sample and Velocity Traverses for Stationary Sources.
 - b. Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate.
 - c. Method 3 or 3A: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight
 - d. Method 4: Determination of Moisture in Stack Gases.
 - e. Method 6C: Determination of Sulfur Dioxide Emissions From Stationary Sources.
 - f. Method 7E: Determination of Nitrogen Oxide Emissions From Stationary Sources.
 - g. Method 10: Determination of Carbon Monoxide Emissions From Stationary Sources.
 - h. Method 18 or 25A: Determination of Volatile Organic Compounds Emissions From Stationary Sources
 - i. Method 19: F-factor Methodology

C. Oil-Water Separator Subject to NSPS, Part 60, Subpart QQQ.

EU	Point	Type	Contents
OWS	TBD	Sealed Container	Sour Water Stripper Feed

- i. The permittee shall comply with the applicable sections of NSPS, 40 CFR Part 60, Subpart QQQ, VOC Emissions From Petroleum Wastewater Systems.
[40 CFR 60.690-699]

- 2. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations, which qualify as Trivial Activities.
[OAC 252:100-8-6 (a)(3)(B)]
 - a. For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: records of the capacity of the tanks and the contents.
 - b. For activities (except for trivial activities) that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions or a surrogate measure of the activity (annual).

- 3. Certain equipment constructed as part of the DHT project within the refinery is subject to NSPS, 40 CFR Part 60, Subpart GGGa and all affected equipment shall comply with all applicable requirements. [40 CFR Part 60, NSPS, Subpart GGGa]
 - a. 60.590a Applicability and designation of affected facility.
 - b. 60.591a Definitions.
 - c. 60.592a Standards.
 - d. 60.593a Exceptions.

- 4. The Refinery is subject to NESHAP, 40 CFR Part 61, Subpart FF and shall comply with all applicable requirements. [40 CFR Part 61, NESHAP, Subpart FF]
 - a. § 61.342 Standards: General.
 - b. § 61.343 Standards: Tanks.
 - c. § 61.344 Standards: Surface Impoundments.
 - d. § 61.345 Standards: Containers.
 - e. § 61.346 Standards: Individual drain systems.
 - f. § 61.347 Standards: Oil-water separators.
 - g. § 61.348 Standards: Treatment processes.
 - h. § 61.349 Standards: Closed-vent systems and control devices.
 - i. § 61.350 Standards: Delay of repair.
 - j. § 61.351 Alternative standards for tanks.
 - k. § 61.352 Alternative standards for oilwater separators.
 - l. § 61.353 Alternative means of emission limitation.
 - m. § 61.354 Monitoring of operations.
 - n. § 61.355 Test methods, procedures, and compliance provisions.
 - o. § 61.356 Recordkeeping requirements.
 - p. § 61.357 Reporting requirements.

5. Certain equipment within the refinery is subject to NESHAP, 40 CFR Part 63, Subpart CC and all affected equipment shall comply with all applicable requirements.

[40 CFR Part 63, NESHAP, Subpart CC]

- a. § 63.63.642 General Standards
- b. § 63.643 Miscellaneous Process Vent Provisions
- c. § 63.644 Monitoring for Miscellaneous Process Vents
- d. § 63.645 Test Methods and Procedures for Miscellaneous Process Vents
- e. § 63.646 Storage Vessel Provisions
- f. § 63.647 Wastewater Provisions
- g. § 63.648 Equipment Leak Standards
- h. § 63.652 Emission Averaging Provisions
- i. § 63.653 Monitoring, Recordkeeping, and Implementation Plan for Emissions Averaging
- j. § 63.654 Reporting and Recordkeeping Requirements
- k. The permittee shall comply with the provisions of 40 CFR Part 63 Subpart A as specified in Appendix to Subpart CC, Table 6.

6. The permittee shall maintain records as specified in Specific Condition 1 including but not limited to those listed below. These records shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request.

[OAC 252:100-43]

- a. Records showing compliance with 365-day rolling averages (monthly) established in Specific Condition 1.
- b. Records showing compliance with emission limits (monthly) established in Specific Condition 1.
- c. Heater fuel usage (monthly) and heat content (quarterly) for Heaters B4101 and B4102.
- d. Records required by 40 CFR Part 60, NSPS, Subparts A, J, GGGa, and QQQ, Part 61, NESHAP, Subparts A and FF, and Part 63, NESHAP, Subparts A, CC, and UUU.

7. The permittee shall be authorized to operate the listed equipment continuously (24 hours per day, every day of the year).

[OAC 252:100-8]

8. The permittee shall submit an application to update the Title V Permit within 180 days of start-up to incorporate the requirements of this permit.

[OAC 252:100-8]

**MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(January 24, 2008)**

SECTION I. DUTY TO COMPLY

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

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

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.

[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

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

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

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

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

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

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

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

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

B. Records of required monitoring shall include:

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

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

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

[OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

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

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

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

[OAC 252:100-43]

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

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

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

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

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

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

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

K. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM₁₀). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

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

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

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

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period; and a statement that the facility will continue to comply with all applicable requirements.

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

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

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

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

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

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification.

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

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC

252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

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

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.

[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

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

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

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

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

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

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

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.

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

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage

to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

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

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

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

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

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

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

SECTION XII. REOPENING, MODIFICATION & REVOCATION

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

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

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

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

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

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

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

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

SECTION XIII. INSPECTION & ENTRY

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

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

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

SECTION XIV. EMERGENCIES

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

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

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

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires

immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

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

- (1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
- (2) the permitted facility was at the time being properly operated;
- (3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit. [OAC 252:100-8-6 (e)(2)]

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

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

SECTION XV. RISK MANAGEMENT PLAN

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

SECTION XVI. INSIGNIFICANT ACTIVITIES

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

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

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

SECTION XVII. TRIVIAL ACTIVITIES

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

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

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating.

[OAC 252:100-8-6(a)(10) and (f)(1)]

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

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

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

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

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

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

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

- (3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for:
 - (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
 - (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
 - (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
 - (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property. [OAC 252:100-25]
- (4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]
- (5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]
- (6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]
- (7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

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

- (1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
- (2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
- (3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs. [40 CFR 82, Subpart A]

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the

vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B:

- (1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
- (2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
- (3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
- (4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
- (5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
- (6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166. [40 CFR 82, Subpart F]

SECTION XXI. TITLE V APPROVAL LANGUAGE

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

- (1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
- (2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
- (3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
- (4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R. § 70.8(a) and (c).

- (5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
- (6) The DEQ complies with 40 C.F.R. § 70.8(d).
- (7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
- (8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
- (9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).
- (10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

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

SECTION XXII. CREDIBLE EVIDENCE

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

[OAC 252:100-43-6]



PART 70 PERMIT

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

Permit No. 98-014-C (M-14)

Sunoco, Inc.,

having complied with the requirements of the law, is hereby granted permission to construct the DHT Project at the Sunoco Tulsa Refinery, at 1700 S. Union, Tulsa, Tulsa County, Oklahoma,

subject to Standard Conditions dated January 24, 2008, and the Specific Conditions, both attached.

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

Director, Air Quality Division

Date

Andrew Haar, Environmental Manager
Sunoco, Inc.
1700 S. Union
Tulsa, OK 74107

Re: Construction Permit No. **98-014-C (M-14) PSD**
Tulsa Refinery

Dear Mr. Haar:

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

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

Thank you for your cooperation in this matter. If I may be of further service, or you have any questions about this permit, please call me at (405) 702-4199.

Sincerely,

Phillip Martin, P.E.
Engineering Section
AIR QUALITY DIVISION