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

**MEMORANDUM March 11, 2016**

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**SUBJECT:** Minor Source General Permit for Oil and Gas Facilities (GP-OGF) Background Document

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## SECTION I. INTRODUCTION

This General Permit has been developed to authorize construction and/or operation of facilities with potential emissions less than 100 tons/year (TPY) of a regulated pollutant in an attainment area, less than 100,000 TPY of $CO_2e$, less than 10 TPY of any single hazardous air pollutant (HAP), and less than 25 TPY of total HAP.

In addition, this permit will distinguish synthetic minor facilities with actual emissions below 79.99 TPY and those facilities with actual emissions equal to or above 80 TPY.

The permit is limited to air pollutant emitting sources located at Oil and Gas Facilities (OGF) that are designed and operated for the production, gathering, processing, storage, and/or transportation of crude oil, refined petroleum products, natural gas, and natural gas liquids (NGL), including condensate. These facilities are typically categorized under the following SIC and NAICS codes:

| SIC Code | NAICS Code | Industry |
|---|---|---|
| 1311 | 211111 | Crude Petroleum and Natural Gas Extraction |
| 1321 | 211112 | Natural Gas Liquid Extraction |
| 4612 | 48611 | Pipeline Transportation of Crude Oil |
| 4613 | 48691 | Pipeline Transportation of Refined Petroleum Products |
| 4922 | 48621 | Pipeline Transportation of Natural Gas |
| 5171 | 42271 | Petroleum Bulk Stations and Terminals |
| 5172 | 42272 | Petroleum and Petroleum Products Wholesalers (except Bulk Stations and Terminals) |

Facilities with the same or substantially similar operations and activities, which emit the same types of regulated air pollutants, and which are subject to the same or similar standards, limitations, operating requirements, and monitoring requirements can be covered under this permit. Permits issued to these facilities must address all air emissions from all sources at these facilities. Thus, this permit is designed to include those sources typically expected to be present at OGF, including storage tanks, VOC Loading Operations, combustion equipment (engines, heaters, boilers, and flares), glycol dehydration units, amine units, and fugitive emission sources. Facilities with other sources of air emissions are not eligible for coverage under this permit, unless a minor source construction permit is obtained and the requirements of that permit are incorporated into an Authorization to Operate. For instance, some OGF may have amine units that require applicability review, compliance demonstrations, and/or specific conditions for compliance with OAC 252:100-31 and NSPS Subpart LLL.

Table I-1 shows the approximate number of facilities located in Oklahoma that are potentially eligible for coverage under this permit.

**TABLE I-1.OKLAHOMA MINOR OIL and GAS FACILITIES**

| SIC Code | Industry | Facilities Reporting To AQD Inventory (2003) | Facilities Reporting To AQD Inventory (2011) | Facilities Reporting To AQD Inventory (2014) |
|---|---|---|---|---|
| 1311 | Crude Petroleum and Natural Gas Extraction | 232 | 1663 | 5451 |
| 1321 | Natural Gas Liquid Extraction | 21 | 86 | 91 |
| 4612 | Pipeline Transportation of Crude Oil | 73 | 92 | 123 |
| 4613 | Pipeline Transportation of Refined Petroleum Products | 5 | 16 | 13 |
| 4922 | Pipeline Transportation of Natural Gas | 269 | 333 | 278 |
| 5171 | Petroleum Bulk Stations and Terminals | 11 | 14 | 24 |
| 5172 | Petroleum and Petroleum Products Wholesalers (except Bulk Stations and Terminals) | 8 | 12 | 5 |
| | **Total** | **619** | **2216** | **5985** |

## SECTION II. DEFINITIONS

The following definitions apply to this memorandum and general permit. All defined terms are written with initial capital letters in the memorandum and permit.

**"Certified Engine"** means any engine that has been certified by the EPA to meet emissions standards for the purposes of meeting an NSPS or NESHAP.

**"Class I"** means a facility that has an enforceable limit less than 80% of major source levels for each regulated air pollutant.

**"Class II"** means a facility that has an enforceable limit of less than 100% of major source levels for each regulated air pollutant and is not a Class I facility.

**"Engine"** means any reciprocating internal combustion engine or any gas-fired turbine.

**"Emergency Use Engine"** means any engine that drives an emergency power generator, peaking power generator, firewater pump, or other emergency use equipment, and operates no more than 500 hours per year.

**"Emissions Limited Engine"** means any engine that has pound per hour emissions limitations specified under the conditions of an Authorization. Pound per hour emission limits shall be established for all engines located at a Class II facility and for all controlled engines; except for Certified Engines; except for Emergency Use Engines; except for engines subject to NSPS which have federally enforceable emission limits.

**"Maximum Rated Horsepower"** means an engine's maximum horsepower at ISO or manufacturer's standard conditions and maximum RPM, or an engine's maximum horsepower at engine site conditions and maximum RPM.

**"Notice of Modification"** means a written notice informing AQD of: (1) any modification or change of operations at the facility that would add a piece of equipment or a process that is subject to NSPS or NESHAP, or that would modify a piece of equipment or a process such that it becomes subject to NSPS or NESHAP, or that would change its facility classification (either from or to a True Minor Facility, a Class I Facility, or a Class II facility); or (2) any modification to add a storage tank with a capacity of 400 gallons or more storing VOC, a VOC Loading Operation, any combustion equipment, or any dehydration unit; or (3) any modification to change the hourly emissions limitations of an Emissions Limited Engine; or (4) any modification to add or remove a 6 TPY tank limit to address NSPS Subpart OOOO needs; or (5) any modification to add, modify, reconstruct, or replace an engine. Such notice shall contain calculations of the facility's new facility-wide potential to emit; the change in the facility's classification, if any; and the engine's potential to emit (g/hp-hr, lb/hr, and TPY) for all engines at the facility. Any emissions limits for $NO_X$ and CO (lb/hr) cited in the latest Notice of Modification, for any Emissions Limited Engine, become permit limitations for that engine and an enforceable part of the existing Authorization to Operate. The permittee shall attach a copy of the latest Notice of Modification to a copy of the Authorization to Operate kept either on site, at a nearby manned facility, or at the nearest field office.

**"Representative Extended Wet Gas Analysis"** means an extended analysis (using GPA 2286 or similar approved methods) that provides speciated data for HAP components benzene, toluene, ethyl benzene, xylenes, and n-hexane. The sample must be representative of the maximum expected HAP content for normal operations of the glycol dehydrator or amine unit.

**"Synthetic Minor Facility"** means a facility that has the potential to emit over major source levels of any regulated air pollutant but with controlled actual emissions below major source levels.

**"True Minor Facility"** means a facility that has the potential to emit, without controls, less than 80 TPY each of $NO_X$ and CO.

**"Uncontrolled Engine"** means an engine, with or without an Air to Fuel Ratio Controller, that has no catalytic or oxidation catalyst control.

**"VOC Loading Operation"** means loading liquid VOC into a tank truck or trailer for transportation offsite or unloading of liquid VOC from a tank truck or trailer to a storage tank onsite. A VOC Loading Operation does not have the physical equipment (loading arm and pump) to conduct the type of loading regulated by OAC 252:100-37-16 and 100-39-41 for VOC loading facilities, even though it may or may not use tank trucks or trailers that meet the requirements for delivery vessels in OAC:252-100-39-41(d).

**"Voluntary Controls"** means facilities not requesting the use of control devices for compliance with an emissions cap or federal limits.

## SECTION III. DESCRIPTION

### A. EQUIPMENT

OGF typically have the following emission sources in common: storage tanks, VOC Loading Operations, combustion equipment (engines, heaters, boilers, and flares), glycol dehydration units, amine units, fugitive emission sources (pump seals, compressor seals, valves, flanges, connectors, pneumatic devices, and other components), and de minimis facilities as defined in OAC 252:100, Appendix H.

#### Storage Vessels

Crude oil production sites use tanks to store the produced crude oil prior to truck loading or pumping to pipelines. Crude oil trucking stations use tanks to store crude oil delivered from tank trucks, prior to the crude oil being pumped into pipelines. Breakout tanks are used at pipeline pump stations for surge capacity, sorting, measuring, rerouting, and temporary storage. Compressor stations and natural gas plants use tanks to store slop oil, oily water, and/or condensate prior to truck loading or unloading. Bulk stations and wholesale facilities store refined petroleum products prior to truck loading for delivery to retail stations or customers. Storage tanks emit VOC due to working and breathing losses and flash emissions from volatile liquids.

#### VOC Loading Operations

VOC is emitted from tank trucks being loaded (typically) or unloaded at a facility. The transferred liquids displace vapors present in the truck tank if loading or the storage vessel if unloading. These emissions may consist of vapors remaining from a previous cargo, or may be flashed from the liquid being loaded, or a combination of both. A controlled system may include "vapor balancing" whereby the displaced vapors are returned to the unloading truck tank, or the vapors from loading a truck tank may be routed back to the storage tank and then either recycled by compression back to the process or vented to a combustion device.

#### Combustion Equipment

The vast majority of OGF have one or more engine driven compressors, although large pumps at petroleum liquid storage facilities are typically driven by electric motors. Small heaters, such as crude oil heat treaters, small boilers, and glycol or molecular sieve regenerator heaters exist at many facilities. Flares, incinerators, and thermal oxidizers may also be present at some facilities. All combustion sources emit regulated air pollutants $NO_X$, CO, VOC, $SO_2$, and $PM_{10}$.

#### Glycol Dehydration Units

Both ethylene glycol (EG) and, more typically, triethylene glycol (TEG) dehydration units are used at many minor OGF. These units emit VOC and HAP (benzene, toluene, ethyl benzene, xylene, and n-hexane) from rich glycol flash tank vents and glycol regenerator still vents.

**Amine Units**

Amine units are used to remove $H_2S$ and $CO_2$ (acid gases) from natural gas or natural gas liquids. These units emit $H_2S$, $CO_2$, VOC, and HAP from rich amine flash tank vents and amine regeneration still vents.

**Fugitive Emission Sources**

Equipment components such as pump seals, compressor seals, valves, flanges, connectors, open-ended lines, pneumatic control devices, and other components are the source of fugitive VOC emissions.

**De Minimis Facilities**

OGF often contain equipment that is listed as a de minimis facility under OAC 252:100, Appendix H. De minimis facilities are emission sources that do not require a minor permit unless located at an otherwise permitted facility. The Appendix H list is cited in the General Permit to identify activities/emissions units that are exempt primarily from monitoring and recordkeeping requirements. However, emissions from these activities/emissions units are required to be estimated for compliance with the facility-wide cap in the General Permit. A simplified method for estimating emissions from de minimis facilities is included in the permit.

## B. LIQUIDS STORED

Petroleum liquids stored at these facilities generally include crude oil, slop oil, condensate, and any finished or intermediate liquid products manufactured or extracted in a petroleum refinery such as gasoline, diesel, fuel oil, jet fuel, and kerosene. These facilities can also store ethylene glycols (EG, DEG, and TEG) and methanol for use in dehydrators, for engine cooling solutions, and for injection into refrigerant processes to control hydrate formation. Other stored liquids can include produced water, antifreeze, corrosion inhibitors, and lube oils.

**Crude Oil**

Significant emissions from the storage and loading of crude oil include VOC, hydrogen sulfide ($H_2S$), and the HAP listed in Table II-1. Crude oil contains other HAP, but they have higher molecular weights and the amount emitted is typically negligible compared to the HAP listed. The listed concentrations are the default HAP content values for crude oil in EPA TANKS 4.0.

**Table II-1. Typical Crude Oil Maximum HAP Concentrations**

| Pollutant | CAS Number | Weight % |
|---|---|---|
| Benzene | 71432 | 0.60 |
| Toluene | 108883 | 1.00 |
| Ethyl benzene | 100414 | 0.40 |
| Xylenes | 1330207 | 1.40 |
| n-Hexane | 110543 | 0.40 |

**Condensate**

Condensate, as defined in OAC 252:100-37-2, means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at normal operating conditions. VOC emissions from condensates may also include small amounts of benzene, toluene, ethyl benzene, and xylene (BTEX), and more significant amounts of n-hexane.

**Refined Petroleum Products**

Refined petroleum products include, but are not limited to, the following: gasoline, diesel fuels, fuel oil, jet fuels, kerosene, and naphtha. These refined products can contain the same HAP as listed for crude oil.

**Ethylene Glycols**

Ethylene glycols (EG, DEG, and TEG) are HAP; however, due to the low vapor pressure of these compounds and their water solutions, no emission calculations or specific requirements are necessary at minor OGF.

**Methanol**

Methanol is a HAP; however, due to its relatively low vapor pressure and typically small storage volumes, no emission calculations or specific requirements are necessary at minor OGF other than the requirement of a submerged fill pipe per OAC 252:100-37 Part 3, unless stored at a drilling or production facility for use on site (OAC 252:100-37-4(b)).

**Amine**

Amines (MEA, DEA, TEA, DGA, and MDEA) are VOC; however, due to the low vapor pressure of these compounds and their water solutions, no emission calculations or specific requirements are necessary at minor OGF.

## SECTION IV. EMISSIONS

### A. POTENTIAL TO EMIT

The potential to emit (PTE) pollutants at a facility should be calculated using guidance contained in the DEQ "Potential to Emit Guidance", which is available on the DEQ website at www.deq.ok.gov. Note that facilities for which throughput is dependent on oil and gas field production may use the special procedures outlined in NESHAP 40 CFR, Subpart HH, for determining maximum facility throughput. In addition to the guidance above, start-up and shutdown related emissions , including but not limited to blowdowns and engine start-ups that utilize controls, shall be included in the facility PTE.

## B. REGULATED AIR POLLUTANTS

$NO_X$, CO, VOC, $SO_2$, and $PM_{10}$ are emitted from these facilities. $NO_X$ and CO emissions from combustion sources can be significant and may require control for the facility to be a "synthetic minor" facility. Likewise, VOC emissions from storage tanks may also require control for the facility to be a "synthetic minor" facility. Emissions of $SO_2$ and $PM_{10}$ are primarily from combustion sources and are typically much less than major source levels since most facilities combust natural gas with a total sulfur content of less than 20 grains/100 scf.

### Storage Tanks

The EPA document *Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations* (9/1999) provides guidelines for emission estimation techniques for stationary point sources. The preferred method of estimating working and breathing losses from storage tanks is the use of equations presented in AP-42, Chapter 7. EPA and API have developed software packages (EPA TANKS and API E&P TANK) based on these working and breathing loss equations. The current version of E&P TANK can also provide estimates of flash losses from petroleum storage tanks. AQD has guidance which addresses acceptable methods for estimating VOC flash emissions from storage tanks: "Calculation of Flashing Losses/VOC Emissions from Hydrocarbon Storage Tanks."
(Current Link - http://www.deq.state.ok.us/aqdnew/resources/factsheets/FlashingLosses020916.pdf)

### VOC Loading Operations

VOC emissions from the loading of tank trucks are generally estimated using AP-42 (1/95) Chapter 5.2.2.1.1, Equation 1 and Table 5.2-1 or other equivalent methods approved by Air Quality.

### Combustion Equipment

Combustion equipment such as engines, heaters, boilers, and flares, emit $NO_X$, CO, $SO_2$, VOC, and $PM_{10}$ from the combustion and incomplete combustion of natural gas and liquid fuels. These pollutants can be estimated from emissions factors based on stack test data, manufacturer's data, or emission factors from AP-42, Chapters 1, 3, or 13. Stack test data or manufacturer's data are preferred methods for calculating potential $NO_X$ and CO emissions from engines.

Combustion equipment also emits $SO_2$ due to the combustion of any sulfur compounds present in the fuel. Emission estimates should be based on a mass balance assuming 100% conversion of elemental sulfur in the fuel to $SO_2$. However, when combusting natural gas with total sulfur content of less than 20 gr/100 scf, emissions of $SO_2$ per MMBtu are much less than emissions of $NO_X$ and CO; therefore, specific limits on $SO_2$ emissions are not required when combusting natural gas. The permit will limit the total sulfur content in liquid fuels to less than 0.05 wt% and will restrict the use of liquid fuels to Emergency Use Engines and engines rated at less than 50 horsepower, which will insure that $SO_2$ emissions remain below major source levels.

Emissions of $PM_{10}$ are negligible and in compliance with OAC 252:100-19 for these sources when combusting natural gas. Compliance is also assured for liquid fuel combustion as demonstrated in Section IX.B.3.

**Glycol Dehydration Units**

Glycol dehydration units emit VOC from rich glycol flash tank vents and regenerator still vents. Potential VOC emissions from glycol dehydrator units can be estimated using the GRI-GLYCalc program (Version 4.0 or later), a process simulator program, or the Atmospheric Rich/Lean (ARL) Method. The emissions should be based on the potential to emit by assuming continuous operation using (1) the maximum design dry gas rate for the dehydrator unit, or (2) the maximum facility dry gas rate based on an inherent process limitation such as compressor horsepower or capacity limitations, or (3) the maximum facility dry gas rate based on an inherent limit on gas production, or (4) the maximum annual average dry gas rate for the last 2 years plus a 20% safety factor; a Representative Extended Wet Gas Analysis; the normal process operating temperature and pressure; the expected removal efficiency of any glycol still vent condenser at its maximum design temperature; and the maximum pump rate of the lean glycol circulation pump. Emissions from glycol dehydration units are often controlled by using a condenser on the regenerator still vent and then venting to atmosphere or to the regenerator reboiler firebox, other heaters, or a flare. Emissions from rich glycol flash tank vents are often controlled by combustion or by recycling back to low-pressure inlet gas streams. For combustion of gasses from a glycol still vent or flash tank in a reboiler, only 50% destruction efficiency shall be allowed.

**Amine Units**

Amine units emit VOC from the rich amine flash tank and regenerator still vents. Potential emissions can be estimated using the AMINE-Calc program, a process simulator program, and/or mass balance equations. The emissions should be based on the potential to emit by assuming continuous operation using the maximum throughput, a representative extended gas analysis or natural gas liquid analysis, the normal process operating temperatures and pressures, and the maximum pump rate of the lean amine circulation pump. Emissions from amine unit flash tanks are often controlled by routing the gases to the fuel gas system or by using a flare. Emissions from the regenerator still vent are often controlled by flaring or are vented to the atmosphere.

**Fugitive Emission Sources**

VOC emissions from fugitive equipment components are generally estimated using emission factors from EPA's *1995 Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)* or from other DEQ approved emissions factors.

## C. HAZARDOUS AIR POLLUTANTS (HAP)

Significant amounts of HAP can be emitted from petroleum liquid storage tanks, VOC Loading Operations, engines, and glycol dehydration units. HAP emissions from heaters, boilers, flares,

fugitive emission sources, and the storage of ethylene glycols and methanol are negligible for minor OGF.

**Storage Tanks and VOC Loading Operations**

HAP emissions from tanks storing petroleum liquids, other than condensate, can be estimated using the default crude oil HAP content in the EPA TANKS program or other methods that speciate the amount of HAP contained in the VOC emissions. VOC emissions from the storage and loading of condensate can contain significant amounts of HAP, especially n-hexane.

**Combustion Equipment**

Engines emit HAP including formaldehyde, acrolein, and acetaldehyde, with the most significant being formaldehyde. HAP emissions are generally estimated using manufacturer's data, the emission factors in AP-42 Chapter 3, or other industry generated data.

**Glycol Dehydration Units**

Glycol dehydration units emit HAP from rich glycol flash tank vents and regenerator still vents. Potential HAP emissions from glycol dehydrator units can be estimated using the GRI-GLYCalc program (Version 4.0 or later), a process simulator program, or the Atmospheric Rich/Lean (ARL) Method. The emissions should be based on the potential to emit by assuming continuous operation using (1) the maximum design dry gas rate for the dehydrator unit, or (2) the maximum facility dry gas rate based on an inherent process limitation such as compressor horsepower or capacity limitations, or (3) the maximum facility dry gas rate based on an inherent limit on gas production, or (4) the maximum annual average dry gas rate for the last 2 years plus a 20% safety factor; a Representative Extended Wet Gas Analysis; the normal process operating temperature and pressure; the expected removal efficiency of any glycol still vent condenser at its maximum design temperature; and the maximum pump rate of the lean glycol circulation pump.

**Amine Units**

Amine units emit HAP from rich amine flash tank vents and regenerator still vents. Potential HAP emissions from amine units can be estimated using the AMINE-Calc program or a process simulator program. The emissions should be based on the potential to emit by assuming continuous operation using the maximum throughput, a representative extended gas analysis or natural gas liquid analysis, the normal process operating temperatures and pressures, and the maximum pump rate of the lean amine circulation pump. Emissions from amine unit flash tanks are often controlled by routing the gases to the fuel gas system or by using a flare. Emissions from the regenerator still vent are often controlled by flaring or are vented to the atmosphere.

**D. HYDROGEN SULFIDE**

Some facilities store crude oils containing varying levels of $H_2S$. Available information indicates that $H_2S$ levels in crude oils are dependent upon the field and formation from which a particular

crude oil is produced. Typical sweet crude oils contain zero to 6-ppm $H_2S$ by weight. $H_2S$ has a very high vapor pressure and stable (flashed and weathered from storage) sour crude oils handled by pipeline facilities will typically have much lower maximum $H_2S$ concentrations than production facilities. Section I of Appendix A presents more detailed information on $H_2S$ emissions from crude oil.

Glycol dehydration units that treat sour natural gas can emit $H_2S$ from the regenerator still vent in significant amounts, although sour natural gas typically goes through an amine unit before dehydration. Amine units emit $H_2S$ from rich amine flash tank vents and regenerator still vents. Potential $H_2S$ emissions from amine units can be estimated using the methods from Appendix A.

### E. GREENHOUSE GASES

Most of the facilities that meet emissions levels to qualify as a minor source under OAC 252:100-7 for regulated pollutants other than GHGs will not be affected by the GHG regulations. However, certain facilities may be impacted. Because of this, all facilities should take into consideration their GHG emissions when reviewing permit rule applicability. ODEQ is currently only requesting GHG emission estimates for minor source permit applications on a case-by-case basis, based on the equipment being proposed by the applicant. Should a facility determine there is a need to take an enforceable permit limit to avoid applicability of either the PSD or TV program, the facility should request such in a minor source construction permit application and any specific conditions required to ensure compliance with GHG emission limitations can then be incorporated into an Authorization to Operate. Once the enforceable limit is requested, the final permit would include GHG limits in terms of carbon dioxide equivalent ($CO_2e$), with appropriate monitoring and recordkeeping requirements.

## SECTION V. PERMIT STRUCTURE

This general permit is designed for minor facilities (i.e., with actual emissions less than 100 TPY of a regulated pollutant in an attainment area, less than 100,000 TPY of $CO_2e$, less than 10 TPY of any single HAP, and less than 25 TPY of total HAP). The single permit can authorize both construction and operation, and can be used both for new sources and for modifications at existing sources. Major sources must obtain coverage under a major source construction permit and Part 70 permit.

The general permit is structured so that eligible facilities can obtain an Authorization to Construct and Authorization to Operate under the permit, or can obtain a minor source construction permit and then an Authorization to Operate under the permit, or can obtain an Authorization to Construct under the permit and then a minor source operating permit and pay all applicable fees. This should allow applicants the greatest flexibility for obtaining coverage under the permit. No site-specific determinations can be made in issuance of an Authorization to Construct under a general permit. However, once these site-specific determinations have been completed and drafted into an individual minor source construction permit as emissions limitations and/or specific conditions, they can then be incorporated into the Authorization to Operate under a general permit.

In addition, certain other options usually available by regulation had to be disallowed so that no site-specific determinations were made in issuance of an Authorization to Construct under the general permit. For example, facilities with amine units that have uncontrolled amine regeneration still vents and sour crude oil storage sites cannot obtain an authorization to construct because these types of facilities require a site-specific determination of compliance with the ambient $H_2S$ standard of OAC 252:100-31-7. Also, facilities with "new fuel-burning equipment" subject to OAC 252:100-33 cannot obtain an Authorization to Construct. Alternate emissions reduction authorizations are not allowed under an Authorization to Construct under this permit, as these site-specific limitations require Air Quality Council approval. Similarly, several regulations allow exceptions from specific requirements "if approved by the Executive Director." These approvals also require a site-specific determination that cannot be reasonably made in issuance of an Authorization to Construct under this permit.

All conditions in the permit have been derived directly from applicable requirements given in OAC 252:100, Air Pollution Control, as promulgated to implement the Oklahoma Clean Air Act. The permit is formatted so that the first section establishes emissions limitations. Then specific conditions are given for each emissions unit allowed under the permit. Each section contains a list of emissions limitations, operational conditions, and monitoring and recordkeeping conditions developed to assure compliance with applicable requirements. Conditions to assure compliance with those state regulations that implement federal requirements; e.g., NSPS and NESHAP, are also incorporated as a specific condition for the permit. These emission unit-specific conditions, as required by Oklahoma regulations, are generally established in the Authorization to Construct under this permit, or by a minor source construction permit, and then incorporated into a subsequently issued Authorization to Operate for the facility. Additionally, a section of standard conditions contain those requirements applicable to all minor facilities.

Specific numeric emissions limitations are usually required for sources that have the potential to exceed a threshold value or violate an applicable requirement. However, this general permit establishes those limitations as a facility-wide cap on emissions from the facility, rather than establishing limitations on individual emission units, except where hourly emissions limits on engines are required for compliance methods or TPY to avoid an otherwise applicable limit. The permit initially establishes a facility-wide emissions cap, which may include pre-approved changes foreseeable at the time of permit application. Certain modifications, e.g., adding, modifying, replacing equipment, changing fuels, or increasing operating hours of equipment, or adding or removing a unit specific TPY limit, are pre-approved so long as the facility remains in compliance with its facility-wide emissions cap.

This approach should greatly reduce the burden on both the permittee and AQD by eliminating the need for construction permits, permit modifications, or new Authorizations when making certain changes to the facility. Notification to DEQ within 10 days following the start of operation is required for certain specified changes that do not result in an exceedance of the facility-wide emissions cap.

## SECTION VI. EMISSIONS LIMITATIONS

### A. FACILITY-WIDE EMISSIONS CAP

Emissions limitations specified in the permit are established from applicable federal and state requirements, or from a limitation that the source assumes to avoid an applicable requirement, or from limitations established in previously issued state or federal permits for the facility. Provided, however, that source assumed limitations and/or limitations from previously issued permits must be equivalent to or more stringent than the federal and state applicable requirements.

Because of the similarity of emissions and emissions units at minor OGF, specific numeric emissions limitations need not be developed for each emissions unit; except where hourly emissions limits on engines are required for compliance methods as discussed below; except where tank TPY limits are required; or except where units have specific TPY limits. A facility may take a facility-wide emissions cap for each regulated pollutant that is just below major source levels.

The permit requires the calculation of actual facility-wide emissions, as a monthly, 12-month rolling total, to determine compliance with each facility-wide emissions cap. The facility-wide annual emissions must include emissions from each source located at the facility, including emissions related to start-up and shutdowns. A direct comparison of the calculated emissions can then be compared to the permitted level to determine compliance with the specific condition in the permit. In those cases where a numerical limitation is not specifically developed to demonstrate compliance, other methods (e.g., work practices, parametric monitoring, operational limits, modeling analyses, etc.) are required by the permit to assure compliance.

General EPA policy and preference is to not have emission compliance periods longer than one month, i.e., a 12-month rolling total is preferred for compliance with annual emissions limitations. Also, to demonstrate compliance with the facility-wide emissions caps, the permit requires the use of the hourly potential to emit for emissions from engines and glycol dehydration units, which can be significantly higher than actual emissions.

Note that facilities covered by a general permit are not required to obtain an Authorization to Construct when adding a piece of equipment subject to NSPS or NESHAP already preauthorized by the permit (e.g., 40 CFR 60, Subparts A, Dc, K, Ka, Kb, GG, KKK, IIII, JJJJ, KKKK, or OOOO; or 40 CFR 63, Subpart HH for TEG units, Subpart ZZZZ for engines at area sources and Subpart BBBBBB for gasoline distribution bulk terminals, bulk plants and pipeline facilities at area sources). An Authorization to Construct, and a new Authorization to Operate, is not needed for most other changes at the facility, so long as facility emissions after the change do not exceed the facility-wide cap. To assure continuing compliance with these limits, the permittee must estimate emissions periodically, especially after a change at the facility, and maintain a current equipment inventory to document that such changes do not cause emissions to exceed the facility-wide cap. For certain modifications at the facility, the permittee must send in a Notice of Modification to AQD documenting that these items have been done.

## B. HOURLY EMISSIONS LIMITATIONS ON ENGINES

Hourly emissions limitations are required for $NO_X$ and CO for all engines (Emissions Limited Engines) unless the engine is an Emergency Use Engine; unless the engine is subject to an applicable short term federal standard such as NSPS, Subpart JJJJ; unless the engine could be considered an uncontrolled engine at a True Minor Facility but is using Voluntary Controls; or unless the engine is an Uncontrolled Engine located at a True Minor Facility. The hourly emissions limitations shall be based on manufacturer's data, EPA reference testing, or the latest revision of AP-42, Chapter 3. Appropriate safety factors may be applied. In addition, when federal reference testing is required and testing is not done under maximum representative operating conditions (i.e., less than 90% load), hourly emissions limits are required. If emissions testing is not available upon issuance of the Authorization to Operate and subsequent tests are reported to the agency demonstrating lower load testing, the permit may be reopened to incorporate appropriate hourly limits, only for the engines which that scenario applies.

$H_2CO$ control efficiency shall be at or below the level requested for CO provided it is in compliance with the CO limit as required by the General Permit.

## C. COMPLIANCE WITH THE CAP FOR STORAGE TANKS

The permittee will be required to maintain records of the type and capacity of all storage tanks at the facility with a capacity of 400 gallons or more that store VOC (as defined in OAC 252:100-1-3). In addition, the permittee will be required to include emissions of VOC and HAP from these storage tanks, based on actual throughputs, to demonstrate compliance with the facility-wide emissions cap for VOC and HAP. In addition, a facility may request a 5.99 TPY limit for any VOC storage tanks.

OAC 252:100-31-7 establishes an ambient air standard for $H_2S$ emissions. $H_2S$ emissions from storage tanks are of concern since these facilities may store/distribute crude oils with varying levels of $H_2S$ content. Associated levels of $H_2S$ are typically low, except for sour crude oils. To assure compliance with OAC 252:100-31, eligibility for the general permit will be restricted to those facilities that can demonstrate compliance with OAC 252:100-31-7 through permit eligibility restrictions and crude oil $H_2S$ concentration limitations developed for the general permit and as presented in Appendix A.

## D. COMPLIANCE WITH THE CAP FOR VOC LOADING OPERATIONS

The permittee will be required to include emissions of VOC and HAP from all loading operations, based on actual throughputs, to demonstrate compliance with the facility-wide emissions cap for VOC and HAP. Emissions of VOC and HAP from loading operations are typically low, when loading large volumes of liquid, loading emissions factors should be calculated using the procedures of AP-42 (1/95) Chapter 5.2.2.1.1, Equation 1 and Table 5.2-1 or other equivalent methods approved by Air Quality. Emissions of $H_2S$ from VOC Loading Operations are expected to be negligible as demonstrated in Appendix A.

## E. COMPLIANCE WITH THE CAP FOR COMBUSTION EQUIPMENT

### Sulfur Dioxide Emissions

As shown in Appendix A, in order to demonstrate compliance with OAC 252:100-31 Part 2 and Part 5, the permit will have the following limits:

a. Total sulfur content in natural gas fuel of no more than 20 gr/100 scf.
b. Total sulfur content in liquid fuel of no more than 0.05% by weight.
c. Total installed fired duty from all combustion equipment, other than engines, is limited to 50 MMBtu/hr.

The total amount of engine horsepower that can be operated at a facility and still remain a minor source for $NO_X$ and/or CO is about 5,000 horsepower (hp) for rich burn and 8,000 hp with lean burn engines. This inherent restriction and the limits listed above will limit potential $SO_2$ emissions to about 11 TPY for continuous operation of all combustion sources.

With the above permit restrictions, the potential to emit for $SO_2$ is limited to a maximum of less than 20 TPY for all combustion equipment at OGF and, therefore, no annual compliance calculations are required. The permit will restrict eligibility to those OGF with amine units that are not subject to OAC 252:100-31-26 unless a minor source construction permit is obtained and any specific conditions required to ensure compliance with $SO_2$ emission limitations are then incorporated into an Authorization to Operate.

### $NO_x$ and CO Emissions

To reduce the regulatory burden on the permittee and AQD, the general permit provides exemptions from hourly emissions limitations and periodic tests of $NO_X$ and CO emissions from some engines. However, a one-time initial test of $NO_X$ and CO emissions is required for these engines, except for Emergency Use Engines or engines subject to initial testing under NSPS, to demonstrate that the facility has potential to emit less than the facility-wide emissions cap for $NO_X$ and CO. Also, the engines are always subject to unscheduled compliance testing by AQD. These exemptions include:

a. All Emergency Use Engines. This is present AQD policy.
b. All Uncontrolled Engines at a True Minor Facility. For the general permit, the emissions calculations for Uncontrolled Engines are based on the engine's potential to emit. An engine's potential to emit will be based on continuous operation, the engine's Maximum Rated Horsepower, and the highest manufacturers' emissions factors for any of the settings at which the engine can be operated, e.g., $NO_X$ at "best economy" and CO at "best power". This is a conservative approach to emissions calculations. When combined with the 80 TPY potential emissions limit required for the facility to be classified as a True Minor Facility, there is ample room for variations in engine operations to ensure compliance with the facility-wide emissions caps.

c. All engines subject to an applicable federal short term emission limit such as NSPS, Subpart JJJJ.
d. All engines that are otherwise uncontrolled engines at a true minor facility but are nevertheless using a catalytic converter or an oxidation catalyst.

For all other Uncontrolled Engines, the general permit requires hourly emissions limitations and periodic testing of $NO_X$ and CO emissions.

Compliance with $NO_X$ and CO hourly emissions limits for emission limited engines using a control device (e.g., catalytic converters or oxidation catalyst), is not as straightforward, and is much more critical. Catalytic converters and oxidation catalysts typically have pollutant conversion efficiencies as high as 90 to 95% pollutant reduction. Thus, if the catalyst fails or is bypassed substantially through channeling, or, for three-way NSCR, if the AFRC controller is not maintaining the appropriate amount of excess oxygen in the engine exhaust (typically less than 0.5% oxygen), a single engine could become a major source if operated for even a short period of time out of compliance. Therefore, hourly emissions limitations for $NO_X$ and CO are required for Emissions Limited Engines. A specific condition requiring quarterly testing of $NO_X$ and CO emissions from each Emissions Limited Engine is included in the permit. In addition, the permit will require monthly parametric monitoring to assure proper operation of the catalyst and AFRC (if applicable) and thus assure compliance between quarterly testing.

Engines subject to NSPS Subparts IIII or JJJJ which establishes enforceable short term emission limits, testing, and continuous compliance requirements are not subject to quarterly testing or hourly emission limits.

$NO_X$ and CO emissions from heaters and boilers are much lower per MMBtu of fired duty than are emissions from engines. AP-42, Table 1.4-1 lists typical emission factors for natural gas combustion in small heaters (fired rating of less than 100 MMBtu/hr). $NO_X$ emissions are approximately 100-lb/$10^6$ scf and CO emissions are approximately 84-lb/$10^6$ scf. With the permit limit of 50 MMBtu/hr on the total of all gas-fired combustion equipment, excluding engines and emergency relief flares, these emission factors give a PTE for $NO_X$ of approximately 25 TPY and for CO of approximately 20 TPY. Therefore, no specific emission limitations or compliance demonstrations are required in the permit.

The permittee will be required to include emissions of $NO_X$ and CO from all combustion equipment, based on actual operating hours, to demonstrate compliance with the facility-wide emissions cap for $NO_X$ and CO.

**VOC and $PM_{10}$ Emissions**

$PM_{10}$ emissions from engines and other combustion equipment are typically only 1% (natural gas combustion) to 10% (from diesel engines) as much as $NO_X$ and CO emissions; therefore, no specific limitations or compliance demonstrations are required in the permit for $PM_{10}$, other than restricting liquid fuel to either diesel or No. 2 fuel oil.

The permittee will be required to include emissions of VOC from all combustion equipment, based on actual operating hours, to demonstrate compliance with the facility-wide emissions cap for VOC.

**HAP Emissions**

Engines, lean-burn more so than rich-burn, can emit significant amounts of HAP, including formaldehyde, acrolein, and acetaldehyde, with the most significant being formaldehyde. Estimates of potential formaldehyde emissions may be made using manufacturer's data, stack tests, or emission factors from AP-42, Chapter 3 (for engines older than model year 2000). The permittee will be required to include annual emissions of formaldehyde from all engines, based on actual operating hours, to demonstrate compliance with the facility-wide emissions cap for HAP.

HAP emissions from the combustion of natural gas and liquid fuels combustion equipment such as heaters, boilers, flares, incinerators, and thermal oxidizers are negligible at minor OGF. For instance, the AP-42 factor for formaldehyde emissions from combustion of fuel oil is approximately 0.1% of the emission factor for $NO_X$. Therefore, emissions of HAP from heaters, boilers, flares, incinerators, and thermal oxidizers do not need to be included in the annual emissions calculated for compliance with the facility-wide cap for HAP.

## F. COMPLIANCE WITH THE CAP FOR GLYCOL DEHYDRATION UNITS

The permit requires that the permittee estimate the potential to emit VOC and HAP from any glycol dehydration units and include those emissions in calculating compliance with the facility-wide emissions cap for VOC and HAP. Facilities that have potential HAP emissions from all dehydrator units above 80% of major source levels are required to sample and perform an extended gas analysis on the wet gas once each year. No specific requirements to limit emissions from glycol dehydration units are necessary in the permit when using the potential to emit; however, specific requirements in the permit are necessary to insure compliance when a condenser is used to control emissions and is considered in the calculation of potential to emit. Facilities that require other limitations on a glycol dehydration unit in order to remain a minor source must obtain a minor source construction permit and any specific requirements in that permit can be included in an Authorization to Operate.

## G. COMPLIANCE WITH THE CAP FOR AMINE UNITS

**Hydrogen Sulfide and Sulfur Dioxide Emissions**

Emissions of $H_2S$ for amine units allowed under the permit are required to be controlled using a flare with a minimum control efficiency of 95%. Using a flare, $H_2S$ is oxidized to $SO_2$. The major source threshold for $SO_2$ is around 3,200 SCFD of $H_2S$. The permit requires monitoring of the inlet gas $H_2S$ concentration and throughput to keep the amount of $SO_2$ emitted below major source thresholds. Ambient impacts of $H_2S$ when utilizing a flare to control emissions of $H_2S$ are significantly lower than the ambient standard in OAC 252:100-31-7. At the $H_2S$ throughput levels required to remain a minor source of $SO_2$ and including a required 95% control, $H_2S$

emissions are approximately 3 TPY. Therefore, no additional specific requirements to limit $H_2S$ emissions from amine units are necessary.

Amine units processing natural gas or natural gas liquids from inlet gases containing less than 4 ppmv $H_2S$ have also been shown to have impacts below the ambient standards in OAC 252:100-31-7. The maximum amount of natural gas processed by a single facility is generally much less than 300 MMSCFD. At 300 MMSCFD and 4 ppmv $H_2S$, uncontrolled emissions of $H_2S$ from amine units would amount to 20 TPY. If these emissions were controlled using a flare and a 95% control efficiency, emissions of $SO_2$ would be equivalent to 35 TPY which is also significantly below the major source thresholds. Therefore, no additional specific requirements to limit $H_2S$ or $SO_2$ emissions from amine units at a facility which process natural gas containing less than 4 ppmv $H_2S$ are necessary.

**VOC and HAP Emissions**

Since the amine units allowed under the permit will be required to control emissions from the rich amine flash tank and the amine regeneration still vent to control emissions of $H_2S$, emissions of VOC and HAP will be negligible. Therefore, emissions of VOC and HAP from amine units after control do not need to be included in the annual emissions calculated for compliance with the facility-wide cap for VOC and HAP. No additional specific requirements to limit VOC and HAP emissions from amine units are necessary.

## H. COMPLIANCE WITH THE CAP FOR FUGITIVE EMISSION SOURCES

The permit will require that the permittee maintain an approximate fugitive equipment component inventory. Typically, OGF are not required to calculate fugitives to determine major source status. However, per EPA guidance documents, petroleum storage facilities (PSF) with a total storage capacity exceeding 300,000 barrels and any facility with a source category subject to an NSPS or NESHAP standard in effect prior to August 7, 1980, are required to include fugitive emissions for determination of major source status. However, since PSF > 300,000 barrels are major sources and ineligible for this permit, they are not included. The permit will require those facilities with K or Ka tanks (either subject to or grandfathered from the NSPS) to include fugitive VOC emissions in the emissions calculated for compliance with the facility-wide emissions cap for VOC.

Emissions of HAP from fugitive emission sources are negligible at minor OGF and do not need to be included in the emissions calculated for compliance with the facility-wide emissions cap for HAP. Emissions of $H_2S$ are also negligible as demonstrated in Appendix A.

## I. CALCULATION OF ANNUAL EMISSIONS

For storage tanks and VOC Loading Operations, the emissions of VOC and HAP should be based on the actual annual liquid throughputs.

For an engine, the emissions will be based on the engine's potential to emit (which includes federally enforceable emission limits), including start-up and shutdown, or any hourly permit

limits and the actual hours of operation. For all other combustion equipment, emissions should be based on the potential to emit of each pollutant, in TPY, adjusted for actual fired heat duty and actual annual operating hours, if known.

For glycol dehydration units, the emissions should be based on the unit's potential to emit in lb/hr and either assuming continuous operation or actual hours of operation if known.

For amine units, the emissions should be based on the unit's actual annual throughputs and either assuming continuous operation or actual hours of operation if known.

For fugitive emissions, the emissions should be based on an approximate fugitive component count and emissions factors approved by AQD.

Continuous operation of equipment must be assumed for the calculation of emissions for any emissions source for which the permittee has not kept records of actual hours of operation.

## SECTION VII. ELIGIBILITY

In order to provide the broadest coverage to applicants under this permit and to assure compliance with all applicable requirements, eligibility must be restricted to those minor facilities whose emission units are addressed in this permit. The permit has been developed for facilities designed and operated for the production, gathering, processing, storage, or transportation of crude oil, refined petroleum products, natural gas, and natural gas liquids (NGL), including condensate. Emission units identified as typically present at such a facility, and addressed in the permit, include storage tanks, VOC Loading Operations, engines and other combustion equipment, glycol dehydration units, amine units, and fugitive equipment components. In addition, those emission units identified as a de minimis facility, as defined in OAC 252:100 Appendix H, are also recognized as typically present at such a facility and are addressed in the permit. Any other emissions unit subject to an applicable requirement not included in this permit makes that facility ineligible for coverage under this permit unless a minor source construction permit is obtained and conditions from that permit are incorporated into an Authorization to Operate under this general permit.

### A. INELIGIBLE FACILITIES

The following facilities are not eligible for coverage under this permit.

1. Facilities for which material facts were misrepresented or omitted from the application and the applicant knew or should have known of such misrepresentation or omission.

2. Facilities with emissions units, unless qualified as a de minimis facility under OAC 252:100, Appendix H, that are subject to:

    a. OAC 252:100-8 (Permits for Part 70 Sources)
    b. OAC 252:100-15 (Motor Vehicle Pollution Control Devices)
    c. OAC 252:100-17 (Incinerators)

d. OAC 252:100-23 (Cotton Gins)
e. OAC 252:100-24 (Grain, Feed, or Seed Operations)
f. OAC 252:100-35 (Control of Emissions of Carbon Monoxide)
g. 40 CFR Part 59 (National VOC Standards)
h. 40 CFR Part 82, Subparts B, D, E, G, and H (Stratospheric Ozone Protection)
i. 40 CFR Part 264 (Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities)

## B. FACILITIES INELIGIBLE FOR AN AUTHORIZATION TO CONSTRUCT

The following facilities, unless qualified as a de minimis facility under OAC 252:100, Appendix H, are not eligible to obtain an Authorization to Construct under this permit, but may be eligible for coverage under an Authorization to Operate if they obtain a minor source construction permit and all relevant requirements and limitations in that permit are incorporated into the Authorization to Operate.

1. Facilities with combustion equipment fired with fuels other than liquid petroleum gas (LPG) or natural gas with a maximum total sulfur content greater than 162 ppmv; or stationary reciprocating engines burning liquid fuels other than gasoline, diesel fuel, or No. 2 fuel oil with a total sulfur content greater than 0.05% by weight.

2. Facilities storing/distributing crude oil that do not meet the following:

   a. Facilities that can demonstrate a maximum $H_2S$ concentration of 135 ppmw for all categories of crude oil stored at the facility. Such demonstration must be documented using the methods outlined in Appendix A of this permit.

3. Facilities that use incinerators, regenerative or non-regenerative carbon absorbers, or catalytic systems to control emissions of $H_2S$.

4. Facilities using a vapor-recovery/vapor disposal system, or other equipment of equal efficiency, as required by any part of OAC 252:100-37, Control of VOCs, or 100-39, Control of VOCs in Nonattainment Areas. Note that VOC storage vessels that are subject to equipment standards (e.g., a fixed roof in combination with an internal floating cover, an external floating roof, or a closed vent system and control device) in 40 CFR 60 Subparts K, Ka, or Kb are exempt from the requirements of 252:100-37-15(a) and (b). In addition, VOC storage vessels that are subject to the equipment standards for external floating roofs in 40 CFR 60 Subparts Ka or Kb are exempt from the requirements of 252:100-39-30.

5. Facilities with a VOC loading facility subject to OAC 252:100-37-16(a) or OAC 252:100-39-41.

6. Facilities with amine units that process natural gas with an $H_2S$ content greater than 4 ppmv or that do not control emissions from the rich amine flash tank and amine regeneration vent. The rich amine flash tank can be routed to the fuel gas system or to a

flare. The amine regeneration still vent must be routed to a flare meeting the requirements of OAC 252:100-31-26. Facilities with amine units that process natural gas with an $H_2S$ content greater than 4 ppmv or that do not control emissions from the rich amine flash tank and amine regeneration vent would require a site-specific determination of compliance with the $H_2S$ ambient concentration limit of OAC 252:100-31-7.

7. Facilities with amine units that process more than 0.1276 LTPD of sulfur. Facilities with amine units that process more than 0.1276 LTPD of sulfur would be a major source for $SO_2$.

8. Facilities with "new fuel-burning equipment," as that term is defined in OAC 252:100-33, with a rated heat input of 50 MMBtu/hr or greater for one piece of equipment or a total of 50 MMBtu/hr or greater at the facility.

9. Facilities with emissions units subject to NSPS or NESHAP subparts other than the following:

   a. NSPS requirements under 40 CFR Part 60 Subpart A, Subpart Dc, Subpart K, Subpart Ka, Subpart Kb, Subpart GG, Subpart KKK, Subpart IIII, Subpart JJJJ, Subpart KKKK, Subpart OOOO, or
   b. NESHAP requirements under 40 CFR Part 61, or
   c. NESHAP requirements under 40 CFR Part 63, Subpart HH requirements for triethylene glycol dehydration units at area sources; any Subpart ZZZZ requirements for RICE at area sources; and Subpart BBBBBB requirements for gasoline distribution at bulk terminals, bulk plants and pipeline facilities at area sources.

10. Facilities with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) control systems on any engine or other combustion source. These are control systems that require injection of ammonia, and do not include 3-way catalyst (NSCR) or oxidation catalyst.

11. Facilities that require a specific limitation(s) for a glycol dehydration unit in order to be a minor source, other than operation of a condenser on still vent emissions or the operation of a flare.

12. Facilities with the potential to emit more than 100,000 TPY $CO_{2e}$ and would otherwise be considered a major source of GHG emissions.

13. Facilities located in an area that is federally designated as non-attainment.

14. Facilities that request an Alternative Emissions Reduction Authorization under OAC 252:100-11.

15. Facilities requesting control efficiencies above the levels allowed in Section VIII.B-Control Devices.

The DEQ may not issue a permit authorization sought by an applicant that has not paid all money owed to the DEQ or is not in substantial compliance with the Environmental Quality Code, rules of the Board, and/or the terms of any existing DEQ permits and orders. The DEQ may impose specific conditions on the applicant to assure compliance and/or a separate schedule that the DEQ considers necessary to achieve required compliance. Facilities that are not in compliance with all applicable State and Federal air requirements may become eligible for coverage under this permit through submission of a compliance plan meeting the requirements of Part 3 of this Permit.

The DEQ may refuse issuance of an Authorization to an applicant even though the facility meets the above eligibility criteria. In such a case, DEQ will provide to the facility a written explanation providing the reason(s) for the decision.

## SECTION VIII. APPLICABLE RULES AND REGULATIONS

Applicable rules and regulations are given below for each emission unit, and also for fugitive emissions authorized in this permit, including facility-wide requirements, storage tanks, VOC Loading Operations, combustion equipment, and glycol dehydration units. For brevity, only those applicable requirements that are specific to the particular emissions unit, and not addressed in the facility-wide requirements, are covered in each section.

### A. FACILITY-WIDE REQUIREMENTS

**Oklahoma Air Pollution Control Rules**

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

OAC 252:100-2 (Incorporation by Reference) [Applicable]
The purpose of this Subchapter is to incorporate 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, & 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.

This permit assures compliance with this regulation using the following approach:
A standard condition in the permit requires the permittee to file an annual emissions inventory and pay annual fees based on either emission inventories or allowable emissions.

OAC 252:100-7 (Permits for Minor Facilities) [Applicable]
Part 1 includes definitions and subjects all permitting to the tiered Uniformed Permitting Act. Permits are required to meet public review requirements consistent with the Tier System given in the Uniform Permitting Act.
Part 2 establishes fees for construction and operating permits, Authorizations issued under General Permits, and applicability determinations.
Part 3 establishes construction permit categories and requirements, including that a construction permit require the permittee to comply with all applicable air pollution rules, federal NSPS and NESHAP established under Sections 111 and 112 of the Federal Clean Air Act, and to not exceed ambient air quality standards. A construction permit and subsequent operating permit is required for new facilities and modification of existing facilities.
Part 4 establishes operating permit requirements and requires demonstration of compliance with the emission limits and air pollution control requirements of the construction permit. No specific emission limitation, work practice condition, or other emission standard, or criterion is specified in this subchapter.
Part 9 discusses applicability, general requirements, and registration requirements for facilities that are eligible for a permit by rule.

This permit assures compliance with this regulation using the following approach:
The permit is designed to allow minor facilities to fulfill the requirement to obtain an Authorization to Construct and an Authorization to Operate before starting construction and operation of an eligible facility, or for modifications to existing eligible facilities. A Notice of Intent (NOI) to Construct is required prior to commencing construction or installation of any new facility other than a de minimis facility. Coverage under the general permit is effective upon receipt of the NOI to Construct by the AQD. The earliest of (1) a legible dated U.S. Postal Service postmark (private metered postmarks are not acceptable); (2) a dated receipt from a commercial carrier or the U.S. Postal Service; or (3) a DEQ date stamped application, is acceptable documentation of receipt of the NOI. After construction is complete, an NOI to Operate must be submitted within 180 days of start-up.

The general permit has gone through Tier II review; therefore, only Tier I review will be provided for any Authorizations issued hereunder. In lieu of an Authorization to Construct, an applicant may obtain a minor source construction permit, and then apply for an Authorization to Operate under this permit. Permit conditions have been included in the permit that provide that conditions from a minor source construction permit can be incorporated into the Authorization to Operate as long as the conditions are equivalent to or more stringent than the corresponding conditions in the General Permit. Operational conditions have been included in the permit to require a source to construct and operate all emission units and associated control equipment within a practical range of operating conditions so as to achieve, on a continuous basis, a level of emissions that complies with applicable requirements. Operating and compliance requirements, as well as monitoring and recordkeeping requirements for control devices, are specifically addressed in the permit. The permit also incorporates NSPS which contains initial and continuous compliance requirements and recordkeeping as well as reporting requirements. An initial compliance inspection of the facility may be conducted by the AQD prior to issuance of the Authorization to Operate. Conditions have also been included in the permit to require a compliance demonstration prior to issuance of an Authorization to Operate and continuing

compliance demonstrations to assure that the source continues to meet applicable requirements. Compliance with the facility-wide emissions cap shall be determined by calculating the actual emissions from all emission units located at the facility. Such emissions estimates shall be calculated as specified in the specific conditions for each particular emissions unit, or for equipment not specified, using manufacturer's data, EPA approved emissions software, DEQ approved estimation methods, testing data, or the latest approved version of AP-42, Compilation of Air Pollution Emission Factors. Emissions limitations are required for those sources that have the potential to violate an applicable requirement. These limitations are established as part of the facility-wide emissions cap, not to equal or exceed 100 TPY of any regulated air pollutant for a Class II facility, or 80 TPY of any regulated pollutant for a Class I facility, nor to equal or exceed 10 TPY of any single HAP, or 25 TPY of all HAP. Specific conditions are also included in the permit to address any ambient air quality standards or NSPS and NESHAP requirements. Currently, under Oklahoma's State Implementation Plan (SIP), minor facilities are not required to demonstrate compliance with the NAAQS. However, a permit condition is included in the permit that requires the facility to meet the ambient air quality standards. The permit allows facilities that become subject to an NSPS or NESHAP to incorporate those requirements into an Authorization to Operate. A notice of intent to construct must be issued for the modification of an existing facility that is adding equipment subject to an NSPS or NESHAP not otherwise addressed in the permit or that is making modifications that require a case-by-case determination. After construction is complete, an NOI to Operate must be submitted within 180 days of start-up and a new Authorization to Operate will be issued. All other facility modifications may be constructed without a minor source construction permit, an Authorization to Construct, or a new Authorization to Operate. For certain modifications, the permittee must send a Notice of Modification to AQD within 10 days of the start of operation of the modification.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
Subchapter 9 requires an owner or operator of a regulated facility to report all excess emissions from an air pollution source caused by malfunction, shutdown, start-up, or regularly scheduled maintenance that are in violation of the applicable air pollution control rule, permit, or order of the DEQ. No specific emission limitation, standard, or criterion is specified in this subchapter.

The permit assures compliance with this regulation using the following approach:
Conditions are included in the standard conditions of the permit that require compliance with this subchapter should excess emissions occur.

OAC 252:100-13 (Open Burning) [Applicable]
This subchapter prohibits open burning of refuse and other combustible material except in compliance with OAC 252:100-13-7 and 9. No specific emission limitation or criterion is specified in this subchapter. However, work practice conditions and standards are specified.

The permit assures compliance with this regulation using the following approach:
Subchapter 13 applies to all facilities. Therefore, the permit includes a condition that requires compliance with this subchapter. However, open burning is not expected to take place at facilities covered under this permit. Therefore, no initial compliance demonstration or continuing monitoring, recordkeeping, or reporting requirements associated with this subchapter are included in the permit.

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
This subchapter states no person shall allow or permit the discharge of any fumes, aerosol, mist, gas, smoke, vapor, particulate matter, or any combination thereof, exhibiting greater than 20 percent equivalent opacity except for short-term occurrences. At no time may the opacity exceed 20 percent for one six-minute period in any consecutive 60 minutes nor more than three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity.

The permit assures compliance with this regulation using the following approach:
The only emissions units/activities with the potential for visible emissions are engines, especially liquid fueled engines. Most engines are natural gas fired. In addition, liquid fueled engines restricted to the fuels allowed in this permit have very little potential to violate these opacity requirements. Thus, periodic monitoring of opacity is not being required at any of these facilities. Ongoing operation and maintenance activities at the facility should provide sufficient opportunities to allow owner/operators to identify and take corrective action to address any opacity exceedance. These activities, along with DEQ complaint and compliance activities, should be sufficient to assure compliance with this requirement.

OAC 252:100-29 (Control of Fugitive Dust) [Applicable]
This subchapter prohibits any person from causing or allowing any fugitive dust source to be operated, or any substances to be handled, transported, or stored, or any structure constructed, altered, or demolished to the extent that such operation or activity may enable fugitive dust to become airborne and result in air pollution, without taking reasonable precautions to minimize or prevent pollution. Subchapter 29 further prohibits discharge of visible fugitive dust beyond the property line on which the emissions originated in such a manner as to damage or 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. A list of reasonable precautions is specified in this subchapter.

The permit assures compliance with this regulation using the following approach:
Under normal operating conditions, these facilities have negligible potential to violate this requirement; therefore, it is not necessary to require specific precautions to be taken.

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 permit assures compliance with this regulation using the following approach:
A standard condition is included which states that all required tests shall be made and the results calculated in accordance with test procedures described or referenced in the permit and approved by Air Quality. Permit specific conditions establish minimum monitoring requirements for control devices associated with emission units addressed in this permit. In addition, testing must be performed as specified in 40 CFR Parts 51, 60, 61, 63, and 75, as applicable, unless otherwise specified in an Authorization under this permit.

**Federal Regulations**

Certain state regulations require compliance with federally promulgated regulations. OAC 252:100-7-15(d) requires that construction permits include all applicable requirements, including NSPS and NESHAP. In addition, OAC 252:100-43 provides that any credible evidence may be used for the purpose of establishing whether a person has violated or is in violation of the State Implementation Plan (SIP).

Credible Evidence, 40 CFR Part 51 [Applicable]
This regulation clarifies that "any credible evidence," including data gathered from means other than the use of a specified "reference test method," can be used to prove an alleged emission limitation violation.

The permit assures compliance with this regulation using the following approach:
Conditions are included in the Standard Conditions of the permit to address the credible evidence requirements.

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]
NSPS means a standard of emissions of air pollutants that reflects the degree of emission limitation achievable through the application of the best system of emission reduction that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements, the Administrator of EPA determines has been adequately demonstrated. NSPS apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication of the standard applicable to that facility. Certain notification, recordkeeping, emissions limitations, performance tests, and monitoring requirements are specified in these NSPS regulations.

The permit assures compliance with this regulation using the following approach:
Conditions are included to address the NSPS general notification, recordkeeping, emissions limitations, performance test, and monitoring requirements. Language in the permit emphasizes that NSPS notification and performance test requirements are separate, stand-alone, and independent federal requirements that must be met in addition to any other permit requirements, e.g., equipment addition or change notifications. However, a timely submitted Notice of Modification shall suffice as a notice of the actual date of initial start-up, and as a notice of a

physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies as required by an NSPS (40 CFR 60.7(a)). Conditions specific to a particular NSPS are included for each emissions unit that may be determined to be an affected unit.

National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63[Applicable] NESHAP contains standards that regulate specific categories of stationary sources that emit one or more hazardous air pollutants. These standards require all owners or operators of major and area sources in certain source categories that are constructed or reconstructed to install generally achievable control technology (GACT) unless specifically exempted. Certain notification, recordkeeping, emissions limitations, performance tests, and monitoring requirements are specified in these NESHAP regulations.

The permit assures compliance with this regulation using the following approach:
Conditions are included to address general notification, recordkeeping, emissions limitations, performance test, and monitoring requirements. Language in the permit emphasizes that NESHAP notification and performance test requirements are separate, stand-alone, and independent federal requirements that must be met in addition to any other permit requirements, e.g., equipment addition or change notifications. However, a timely submitted Notice of Modification shall suffice as a notice of the actual date of initial start-up, and as a notice of a physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies as required by an NESHAP (40 CFR 63.9)). Conditions specific to a particular NESHAP are included for each emissions unit that may be determined to be an affected unit.

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

The permit assures compliance with this regulation using the following approach: Facilities subject to 40 CFR Part 82, Subparts B, C, D, E, G, and H are ineligible for an Authorization to Construct. A standard condition of the permit requires compliance with 40 CFR Part 82, Subparts A and F.

<u>Subpart A</u> identifies ozone-depleting substances and divides them into two classes. Petroleum liquid storage facilities may use one or more regulated refrigerants either in a process cooler or condenser, a building air conditioner, or in motor vehicles. 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.

Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment, comply with the standards for recycling and emissions reduction. Conditions are included in the permit to address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

**Non-applicable Oklahoma and Federal Regulations**

Table VIII-1 and Table VIII-2 list the Oklahoma Air Quality Rules and Federal Regulations that are not applicable to facilities covered under this permit on a facility-wide basis. Rules applicable to a specific emission unit are listed separately.

**Table VIII-1- Non-applicable Oklahoma Air Pollution Control Rules**

| | | |
|---|---|---|
| OAC 252:100-8 | Permits for Major Sources | Not a major source |
| OAC 252:100-11 | Alternative Emissions Reduction | Ineligible * |
| OAC 252:100-15 | Mobile Sources | Not a covered source |
| OAC 252:100-17 | Incinerators | Not a covered source |
| OAC 252:100-19-10 & 11 | PM from Wood Waste Burning | Not a covered source |
| OAC 252:100-23 | Cotton Gins | Not a covered source |
| OAC 252:100-24 | Grain Elevators | Not a covered source |
| OAC 252:100-33 | Nitrogen Oxides | Ineligible * |
| OAC 252:100-35 | Carbon Monoxide | Not a covered source |
| OAC 252:100-37, Part 5 | Control of VOC | Not a covered source |
| OAC 252:100-37, Part 7 | Control of Specific Processes | Not a covered source |
| OAC 252:100-39, Part 7 Sections 40, 42, 43, 44-47, & 49 | Emissions of VOCs in Nonattainment Areas and Former Non-Attainment Areas | Ineligible * |

*Ineligible for an Authorization to Construct. May be addressed in a minor source construction permit by specific conditions that are then incorporated into the Authorization to Operate

**Table VIII-2- Non-applicable Federal Regulations**

| | | |
|---|---|---|
| 40 CFR Part 52 | Prevention of Significant Deterioration | Not applicable |
| 40 CFR Part 59 | Consumer/Commercial Products | Not a covered source |
| 40 CFR Part 60 | Subpart LLL, Onshore Natural Gas Processing: $SO_2$ Emissions | Ineligible * |
| 40 CFR Part 61 | NESHAP Subpart J, Equipment Leaks of Benzene | All process streams are below the 10% benzene by weight threshold |
| 40 CFR Part 63 | NESHAP Subpart HHH, Natural Gas Transmission and Storage Facilities Subpart EEEE, Organic Liquids Distribution (Non-Gasoline) | Only applicable to major sources of HAP |
| 40 CFR Part 64 | Compliance Assurance Monitoring | Not a major source |
| 40 CFR Part 68 | Chemical Accident Prevention | Ineligible * |
| 40 CFR Part 82, Subpart B | Stratospheric Ozone for Servicing of MVACs | Ineligible * |
| 40 CFR Part 82, Subpart C | Ban on Nonessential Products | Ineligible * |
| 40 CFR Part 82, Subpart D | Stratospheric Ozone for Federal Procurement | Ineligible * |
| 40 CFR Part 82, Subpart E | Stratospheric Ozone for Labeling of Ozone-Depleting Products | Ineligible * |
| 40 CFR Part 82, Subpart G | Stratospheric Ozone for the Significant New Alternatives Policy Program | Ineligible * |
| 40 CFR Part 82, Subpart H | Stratospheric Ozone for Halon Emissions Reduction | Ineligible * |

*Ineligible for an Authorization to Construct. May be addressed in a minor source construction permit by specific conditions that are then incorporated into the Authorization to Operate.

## B. UNIT-SPECIFIC REQUIREMENTS

### Storage Tank Requirements

**Oklahoma Air Pollution Control Rules**

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of hydrogen sulfide emissions from any new or existing source to 0.2 ppm for a 24-hour average (equivalent to 283 $\mu g/m^3$). The limitation shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.

The permit assures compliance with this regulation using the following approach:
Except for facilities that store crude oil, no significant emission of $H_2S$ is expected from storage tanks at these facilities. Eligibility for an Authorization to Construct under the permit is restricted to those facilities that meet certain limitations as outlined in Appendix A. Facilities that store sour crude oil may apply for a minor source construction permit and then obtain an

Authorization to Operate under this permit. Appendix A documents compliance with Subchapter 31, Part 2 for facilities that meet the limitations. Any emission limitations or specific conditions necessary for compliance with Subchapter 31, Part 2 will be incorporated into the Authorization to Operate.

Facilities that store sour crude oil and which use a flare to convert $H_2S$ emissions from the tanks to $SO_2$ are eligible for the permit.

OAC 252:100-37 (Control of VOCs) [Applicable]
Part 3 requires storage tanks (except pressure tanks) built after 12/28/74, and with a capacity of 400 gallons or more storing a VOC with a vapor pressure of 1.5 psia or greater under actual conditions, to be equipped with a submerged fill pipe or a vapor-recovery system.
Part 3 requires storage tanks (except pressure tanks) built after 12/28/74, with a capacity greater than 40,000 gallons to be equipped with a floating roof or a vapor-recovery system capable of collecting 85% or more of the uncontrolled VOCs.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions, based on this subchapter, are included in the permit for storage tanks. These specific conditions require installation and operation of vapor-loss control devices, which, for storage tanks over 40,000 gallons, include a floating roof or a vapor recovery system. A permanent submerged fill pipe is required for storage tanks over 400 gallons. An Authorization to Construct is not allowed for a facility using a vapor-recovery/vapor disposal system as required by OAC 252:100-37-15(a)(2), or other equipment of equal efficiency, as required by 252:100-37-15(a)(3). Such facilities must obtain a minor source construction permit for these vapor-recovery/vapor disposal systems and operational requirements developed in that construction permit must be incorporated into an Authorization to Operate. Thus, requirements do not need to be included in the general permit for vapor recovery/vapor disposal systems and their associated control devices.

OAC 252:100-39 (VOCs in Non-Attainment and Former Non-attainment Areas) [Applicable]
Part 5 sets control requirements for petroleum liquid storage vessels equipped with external floating roofs, having capacities greater than 40,000 gallons and located in Tulsa and Oklahoma counties.
Part 7 requires that each VOC vessel with a capacity greater than 40,000-gal shall be a pressure vessel or shall be equipped with a floating roof or a vapor-recovery system that consists of a vapor-gathering system capable of collecting 90 percent by weight or more of the uncontrolled VOCs.
Part 7 requires that each VOC storage vessel with a nominal capacity greater than 400-gal and less than 40,000-gal shall be equipped with a submerged fill pipe or be bottom filled. The displaced vapors from each storage vessel with an average daily throughput of 30,000-gal or greater which stores VOCs shall be processed by a system that has a total collection efficiency no less than 90 percent by weight of total VOCs in the vapors.
Part 7 requires that each VOC storage vessel (located in Tulsa County only) with a nominal capacity greater than 2,000-gal and less than 40,000-gal, in addition to being equipped with a submerged fill pipe or being bottom loading, shall be equipped with a vapor control system.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions, based on this subchapter, are included in the permit for storage tanks. Continuing compliance requires that the permittee perform routine inspections of all seal closure devices semi-annually; measure the secondary seal gap annually when the floating roof is equipped with a vapor-mounted primary seal; and maintain records of the types of volatile petroleum liquids stored, the true vapor pressure of the liquid as stored, and the results of the above inspections. An Authorization to Construct is not allowed for a facility using a vapor-recovery/vapor disposal system as required by 100-39-41(a)(2), 100-39-41(b)(2), or 100-39-41(c)(5), or other equipment of equal efficiency, as required by 100-39-41(a)(3). Such facilities must obtain a minor source construction permit for these vapor-recovery/vapor disposal systems and operational requirements developed in that construction permit must be incorporated into an Authorization to Operate. Thus, requirements do not need to be included in the general permit for vapor recovery/vapor disposal systems and their associated control devices.

**Federal Regulations**

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]

Subpart K, Standards of Performance for Storage Vessels for Petroleum Liquids. This subpart applies to storage vessels for petroleum liquids which have a storage capacity greater than 40,000 gallons and are not located at a drilling or production facility prior to custody transfer, and were constructed or modified between March 8, 1974, and May 19, 1978; and those similar vessels greater than 65,000 gallons which were constructed between June 11, 1973, and May 19, 1978. Those vessels storing liquids with a vapor pressure between 1.5 psia and 11.1 psia must be equipped with a floating roof, a vapor recovery system, or their equivalent. Those vessels storing liquids with a vapor pressure greater than 11.1 psia must be equipped with a vapor recovery system. Certain records are required to be kept for these facilities.

Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids. This subpart applies to storage vessels for petroleum liquids that have a storage capacity between 40,000 and 420,000 gallons which are not located at a drilling or production facility prior to custody transfer, and all storage vessels for petroleum liquids with a capacity greater than 420,000 gallons, which were constructed or modified after May 19, 1978. Those vessels storing liquids with a vapor pressure between 1.5 psia and 11.1 psia must be equipped with an external floating roof, a fixed roof with an internal floating roof, a vapor recovery system with 95% weight efficiency, or their equivalent. Those vessels storing liquids with a vapor pressure greater than 11.1 psia must be equipped with a vapor recovery system with 100% collection efficiency and vapor disposal system with 95% weight efficiency. Certain records and performance test are required for these facilities.

Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels). This subpart applies to vessels storing volatile organic liquids (VOL) with a capacity greater than or equal to 19,813 gallons that were constructed or modified after July 23, 1984. This subpart does not apply to storage vessels with a capacity greater than or equal to 39,894 gallons storing a liquid with a maximum true vapor pressure less than 0.51 psia or with a capacity between 19,813 gallons and 39,894 gallons storing a liquid with

a maximum true vapor pressure less than 2.2 psia. Vessels with a capacity greater than or equal to 39,894 gallons storing a VOL with a maximum true vapor pressure between 0.75 psia and 11.1 psia or with a capacity between 19,813 gallons and 39,894 gallons storing a VOL with a maximum true vapor pressure between 4.0 psia and 11.1 psia, must be equipped with either a fixed roof in combination with an internal floating roof, an external floating roof, a closed vent system and control device, or their equivalent. Vessels with a capacity greater than or equal to 19,813 gallons storing a VOL with a maximum true vapor pressure greater than or equal to 11.1 psia must be equipped with a closed vent system and control device or their equivalent. Certain records are required to be kept for these facilities.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NSPS.

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart was promulgated on August 16, 2012, and affects storage vessels located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment that commence construction, reconstruction, or modification after August 23, 2011, and have the potential for VOC emissions equal to or greater than 6 tpy. Storage vessel facilities are subject to standards of §60.5395. A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart. This subpart requires storage tanks with potential VOC emissions of six TPY or greater to reduce emissions by 95%.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements as specified in the NSPS.

**VOC Loading Operations Requirements**

**Oklahoma Air Pollution Control Rules**

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of hydrogen sulfide emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standard shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.

The permit assures compliance with this regulation using the following approach:
Emissions of $H_2S$ from VOC Loading Operations are negligible (see Appendix A).

OAC 252:100-37 (Control of VOCs) [Applicable]
Part 3 requires VOC loading facilities built after 12/28/74, and with a throughput greater than 40,000 gal/day, to be equipped with a vapor collection and disposal system unless all tank trucks or trailers are bottom loaded with hatches closed.

Part 3 requires VOC loading facilities built after 12/28/74, and with a throughput less than 40,000 gal/day, to be equipped with a system for submerged filling of tank trucks or trailers which is installed and operated to maintain a 97 percent submergence factor.

The permit assures compliance with this regulation using the following approach:
Facilities with VOC loading facilities subject to OAC 252:100-37-16(a), load above 40,000 gal/day, are not eligible for an Authorization to Construct. Such facilities must obtain a minor source construction permit for these loading facilities and operational requirements developed in that construction permit must be incorporated into an Authorization to Operate. The permit requires compliance with OAC 252:100-37-16(b) for VOC Loading Operations.

OAC 252:100-39 (VOCs in Non-attainment Areas) [Applicable]
Part 7 requires that each VOC loading facility with an annual throughput of 120,000 gallons or greater shall be equipped with a vapor-collection and/or disposal system. For facilities in Tulsa, stationary VOC loading facilities shall be checked annually in accordance with EPA Test Method 21, Leak Test. Leaks greater than 5,000 ppmv shall be repaired within 15 days. Facilities shall retain inspection and repair records for at least two years. Part 7 also specifies methods to be used to determine leakage from gasoline trucks and associated vapor control systems.

The permit assures compliance with this regulation using the following approach:
Facilities with VOC loading facilities subject to OAC 252:100-39 are not eligible for an Authorization to Construct. Such facilities must obtain a minor source construction permit for these loading facilities and operational requirements developed in that construction permit must be incorporated into an Authorization to Operate.

**Combustion Equipment Requirements**

**Oklahoma Air Pollution Control Rules**

OAC 252:100-19 (PM Emissions from Fuel-burning Equipment) [Applicable]
Subchapter 19 requires that the maximum allowable emissions of particulate matter from engines and other combustion equipment not exceed the following amount:

| Maximum Heat Input (MMBTU) | Allowable Total PM Emissions (lb/MMBTU) |
|---|---|
| Less than or equal to 10 | 0.60 |
| 10,000 or more | 0.10 |

Allowable total PM emissions for units with a heat input of greater than 10 MMBTU but less than 10,000 MMBTU can be calculated using the formulas listed in OAC 252:100 Appendix C.

The permit assures compliance with this regulation using the following approach:
Eligibility for an Authorization to Construct under the permit is restricted to those facilities using liquid petroleum gas, natural gas with no greater than 162 ppmdv total sulfur content, diesel fuel with a sulfur content less than 0.05% by weight, or No. 2 with a sulfur content less than 0.05

wt%. AP-42, Tables 3.2-1,-2, and -3 (7/00) list $PM_{10}$ emissions from gas-fired internal combustion engines as 0.0447 lb/MMBtu for 2-stroke lean-burn engines, 0.009987 lb/MMBtu for 4-stroke lean-burn engines, and 0.01941 lb/MMBtu for 4-stroke rich-burn engines, which are in compliance for all heat input ranges. AP-42, Table 1.4-2 (7/98) lists total PM emissions from natural gas combustion as 0.0075 lb/MMBtu, which is in compliance with all heat input ranges. AP-42, Table 3.3-1 (10/96), lists gasoline fuel $PM_{10}$ emissions as 0.10 lb/MMBtu, which is also in compliance for all heat input ranges. AP-42, Table 3.3-1 (10/96), lists diesel fuel $PM_{10}$ emissions as 0.31 lb/MMBtu for engines rated less than 600-hp, which is also in compliance for all engines rated up to 600-hp. AP-42, Table 3.4-1 (10/96), lists diesel fuel $PM_{10}$ emissions as 0.10 lb/MMBtu, which is also in compliance for all engines rated above 600-hp at all heat input ranges. AP-42, Table 1.3-1 (9/98) lists PM emissions from fuel oil combustion as [9.19S + 3.22] lb/$10^3$ gallons where S is the % sulfur by weight, which is equivalent to approximately 0.02628 lb/MMBtu and is in compliance for all heat input ranges. Thus, any diesel-fired engine eligible for this permit is in compliance with this subchapter.

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

The permit assures compliance with this regulation using the following approach:
The only emissions units/activities with the potential for visible emissions are engines, especially liquid fueled engines. Most engines are natural gas fired. In addition, liquid fueled engines restricted to the fuels allowed in this permit have very little potential to violate these opacity requirements. Thus, periodic monitoring of opacity is not being required at any of these facilities. Ongoing operation and maintenance activities at the facility should provide sufficient opportunities to allow owner/operators to identify and take corrective action to address any opacity exceedance. These activities along with DEQ complaint and compliance activities should be sufficient to assure compliance with this requirement.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of hydrogen sulfide emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standard shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.
Part 5 limits $SO_2$ emissions from any new gas-fired fuel-burning equipment to 0.2 lb/MMBTU heat input for a three-hour average.
Part 5 limits $SO_2$ emissions from any new liquid-fired fuel-burning equipment to 0.8 lb/MMBTU heat input for a three-hour average

The permit assures compliance with this regulation using the following approach:
Eligibility for an Authorization to Construct under the permit is restricted to those facilities using liquid petroleum gas, natural gas with no greater than 20 grains/100 scf total sulfur content, or diesel or No. 2 fuel oil with a sulfur content less than 0.05% by weight. Appendix A documents compliance with Subchapter 31 for any engine eligible for the permit.

OAC 252:100-37 (Control of VOCs) [Applicable]
This subpart, as applied to engines, provides that all fuel-burning equipment shall be operated so as to minimize emissions of hydrocarbons or other organic materials. The equipment should be operated such that it is not overloaded, that it is properly cleaned and maintained, and that temperature and available air are sufficient to provide essentially complete combustion.

The permit assures compliance with this regulation using the following approach:
Specific conditions are included in the permit that require that the permittee properly operate and maintain engines and associated control systems in a manner that will minimize emissions. Operational and maintenance records are required to be kept to document compliance with this requirement.

**Federal Regulations**

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]

Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects Steam Generating Units (defined in the subpart) that commenced construction, modification, or reconstruction after June 9, 1989, and that have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. For Steam Generating Units burning natural gas or LPG, the only applicable Subpart Dc requirement is notification per 40 CFR § 60.48c(a) and records of the daily/monthly amount of fuel combusted per 40 CFR §60.48c(g).

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of this subpart.

Subpart GG, Standards of Performance for Stationary Gas Turbines. This subpart regulates $NO_X$ and $SO_2$ emissions for gas turbines that commenced construction, modification, or reconstruction after October 3, 1977, with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel. These units are subject to the nitrogen dioxide emission limitations of §60.332, the sulfur dioxide emission limitations of §60.333, the requirements of §60.334(h) for fuel monitoring, and the test methods and procedures of §60.335. Monitoring of the fuel nitrogen content is not required if the owner or operator does not take a $NO_X$ allowance for fuel-bound nitrogen. Also, monitoring of fuel sulfur content is not required when a gaseous fuel is fired in the turbine and the owner or operator demonstrates that the gaseous fuel meets the definition of "natural gas" using one of the methods in §60.334(h)(3)(i) or (ii). §60.331 defines "natural gas" as containing 20 grains or less of total sulfur per 100 standard cubic feet and is either composed of at least 70 percent methane by volume or has a gross caloric value between 950 and 1,100 Btu/scf. The fuel monitoring requirements of §60.334(b) are required for liquid fuels.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of this subpart.

Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. This subpart regulates $NO_X$, particulate matter, CO, and Non-methane hydrocarbons (NMOC) from stationary compression ignition internal combustion engines (CI ICE) that commenced construction, modification, or reconstruction after July 11, 2005. Sulfur oxides ($SO_X$) will also be controlled through the use of low sulfur fuel. These units are subject to the emission standards of §60.4304 and §60.4205; the fuel requirements of §60.4207; compliance requirements of §60.4210 and §60.4211; and the testing methods of §60.4212 and §60.4213.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of this subpart.

Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart promulgates emission standards for new SI engines ordered after June 12, 2006, that are manufactured after certain dates, and for SI engines modified or reconstructed after June 12, 2006. These units are subject to the emission standards of § 60.4233; the fuel requirements of §60.4235; compliance requirements of §60.4243; and the testing methods of §60.4244.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NSPS.

Subpart KKKK, Standards of Performance for Stationary Combustion Turbines. This subpart regulates $NO_X$ and $SO_2$ emissions for turbines that commenced construction, modification, or reconstruction after February 18, 2005, with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the higher heating value of the fuel. These units are subject to the nitrogen dioxide emission limitations of §60.4320 and §60.4325, the sulfur dioxide emission limitations of §60.4330, the requirements of §60.4360, §60.4365, and §60.4370 for fuel monitoring, and the test methods and procedures of §60.4400, §60.4405, and §60.4415. Monitoring of fuel sulfur content is not required when natural gas is fired in the turbine and the owner or operator demonstrates that the natural gas contains 20 grains or less of total sulfur per 100 standard cubic feet.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NSPS.

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart affects each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment as well as each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment that commence construction, reconstruction, or modification after August 23, 2011. A centrifugal or reciprocating compressor located at a well site, or an adjacent well site and servicing more than

one well site is not an affected facility under this subpart. Centrifugal compressor facilities are subject to the standards of §60.5380 and reciprocating compressor facilities are subject to the standards of §60.5385.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NSPS.

National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63 [Applicable]

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines). These units are subject to the emission and operating limits of §63.6601 through §63.6604; the requirements of §§63.6610 through §60.6630 for testing and initial compliance; and the notification, reports, and records requirements in §63.6645 through §63.6660.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. Initial and continuing compliance demonstrations are as specified in the NESHAP.

**Glycol Dehydration Units Requirements**

**Oklahoma Air Pollution Control Rules**

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of hydrogen sulfide emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standards shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission. Glycol dehydrators treating sour natural gas have the potential to emit significant amounts of $H_2S$. Sour natural gas is typically treated in a sweetening unit prior to dehydration.

The permit assures compliance with this regulation using the following approach:
Eligibility for an Authorization to Construct is restricted to facilities that do not have glycol dehydration units which treat sour natural gas. Sour gas is natural gas containing greater than 4 ppmv $H_2S$. A facility that has a glycol dehydration unit which processes sour natural gas may apply for a minor source construction permit and then obtain an Authorization to Operate under this permit. Any emission limitations or specific conditions necessary for compliance with Subchapter 31, Part 2 from the construction permit will be incorporated into the Authorization to Operate.

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

The permit assures compliance with this regulation using the following approach:
No specific requirements are needed in this general permit for compliance with Subchapter 42. Those minor OGF that currently have permit specific conditions in order to demonstrate previous compliance with Subchapter 41 Part 5, may use the procedures for this general permit to request a modification for removal of those limitations.

**Federal Regulations**

National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63 [Applicable]

Subpart HH, Oil and Natural Gas Production Facilities. This subpart applies to TEG dehydration units affected emission points that are located at facilities that are major and area sources of HAPs and either process, upgrade, or store hydrocarbons prior to the point of custody transfer or prior to which the natural gas enters the natural gas transmission and storage source category. Facilities covered under OGF-GP are considered an "area" source of HAPs. TEG dehydration units with an actual annual average flow rate of less than 3 MMSCFD or less than 1 TPY of benzene emissions are exempt from control standards, but are subject to recordkeeping.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will have a specific condition requiring compliance with all applicable requirements for TEG units that are subject to NESHAP Subpart HH.

**Amine Units Requirements**

**Oklahoma Air Pollution Control Rules**

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air concentration of hydrogen sulfide emissions from any facility to 0.2 ppm at standard conditions, 24-hour average (equivalent to 283 $\mu g/m^3$). The standard shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.
Part 5, Section 31-26(1) requires $H_2S$ in the waste gas stream from any new petroleum or natural gas process equipment (constructed after July 1, 1972) to be reduced by 95% by removal or by being oxidized to $SO_2$. This requirement does not apply if a facility's emissions of $H_2S$ do not exceed 0.3 lb/hr, two-hour average. The owner or operator is required to install, maintain, and operate an alarm system that will signal a malfunction for all thermal devices used to control $H_2S$ emissions from petroleum and natural gas processing facilities regulated under OAC 252:100-31-26.

Part 5, Section 31-26(2) acid gas streams with a sulfur content of greater than 0.54 LT/D or gas sweetening units or petroleum refinery process equipment which emit more than 100 lb/hr of $SO_2$ shall reduce the sulfur content prior to release to the ambient air by use of a sulfur recovery unit. The sulfur recovery unit shall meet the sulfur recovery efficiencies of OAC 252:100-31-26(2)(C-F).

The permit assures compliance with this regulation using the following approach:
Eligibility for an Authorization to Construct is restricted to facilities with amine units that process sweet natural gas. Sweet natural gas is natural gas with an $H_2S$ content of 4 ppmv or less. Facilities with amine units that process sour natural gas may apply for a minor source construction permit and then obtain an Authorization to Operate under this permit. Any emission limitations or specific conditions necessary for compliance with Subchapter 31, Part 2 from the construction permit will be incorporated into the Authorization to Operate. Appendix A documents compliance with the ambient standard of Subchapter 31 for amine units eligible for the permit. The permittee shall conduct testing of the inlet $H_2S$ concentration at least quarterly to ensure compliance with OAC 252:100-31-7 $H_2S$ ambient air concentration limit of 0.2 ppm (283 $\mu g/m^3$).

This permit requires emissions from the rich amine flash tank to be routed to a flare or to the fuel gas system and the amine regenerator still vent to be routed to a flare with combustion efficiency of 95% or greater to the atmosphere.

The permit also requires acid gas flares at petroleum and natural gas processing facilities to be equipped with an alarm system that will signal when there is no pilot flame.

The permit will also limit applicability of the permit to amine units which process less than 0.1276 long tons per day (LT/D), since at this level a facility would become a major source for $SO_2$.

**Federal Regulations**

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution. This subpart affects sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells that commence construction, reconstruction or modification after August 23, 2011. Sweetening unit facilities are subject to standards of §60.5405, §60.5406 and §60.5407. Facilities that have a design capacity less than 2 LT/D of hydrogen sulfide ($H_2S$) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423(c), but are not required to comply with §§60.5405 through 60.5407 and §§60.5410(g) and 60.5415(g) of this subpart.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of the NSPS.

Subpart LLL, Natural Gas Production. This subpart affects sweetening units and sweetening units followed by a sulfur recovery unit located at an onshore natural gas processing plant that was constructed, reconstructed or modified after January 20, 1984, and on or before August 23, 2011. Sweeting unit facilities are subject to standards of §60.642, §60.643, §60.644, §60.645, §60.646, §60.647 and §60.648. Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide ($H_2S$) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.642(c), but are not required to comply with §§60.642 through 60.646 of this subpart. The provisions of this subpart do not apply to sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released into the atmosphere.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of the NSPS.

**Fugitive Emission Sources Requirements**

**Oklahoma Air Pollution Control Rules**

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of hydrogen sulfide emissions from any new or existing source to 0.2 ppm for a 24-hour average (equivalent to 283 $\mu g/m^3$). The limitation shall not apply to ambient air concentrations occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.

The permit assures compliance with this regulation using the following approach:
As shown in Appendix A, fugitive emissions of $H_2S$ are negligible for the facilities eligible for this permit.

**Federal Regulations**

New Source Performance Standards (NSPS), 40 CFR Part 60 [Applicable]

Subpart KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This subpart requires leak detection and reporting (LDAR) for fugitive components and compressors at natural gas processing plants that were constructed, reconstructed, or modified after January 20, 1984.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of the NSPS.

Subpart OOOO, Crude Oil and Natural Gas Production, Transmission, and Distribution.
This subpart affects each pneumatic controller affected facility, which is a single continuous bleed gas-driven pneumatic controller operating at natural gas bleed rate greater than 6 scfh that

commence construction, reconstruction, or modification after August 23, 2011. Pneumatic controller facilities are subject to the standards of §60.5390 and §60.5402. This subpart also requires leak detection and reporting (LDAR) for equipment leaks at natural gas processing plants and is subject to the standards of §60.5400.

The permit assures compliance with this regulation using the following approach:
Specific operational conditions in the permit adopt these requirements by reference. The permit will require compliance with all applicable requirements of the NSPS.

**Control Devices**

Control devices expected at Minor OGF include floating roofs, vapor-recovery systems, flares, and condensers to reduce VOC and HAP emissions, and catalytic converters on engines to reduce $NO_X$, CO, and VOC (primarily three-way NSCR) or CO and VOC (primarily oxidation catalyst). General permit requirements may be superseded by more stringent monitoring if a minor source construction permit is needed to develop other site-specific conditions to assure compliance with applicable state or federal rules.

The permit contains general requirements to insure compliance with the facility-wide emissions cap or unit specific limits when these control devices are used to reduce pollutant emissions. Facilities with a vapor-recovery system that is determined to be a control device are not eligible for an Authorization to Construct. Those facilities may obtain a minor source construction permit and incorporate any emission limitations and compliance requirements for these control devices in that construction permit into an Authorization to Operate.

OAC 252:100-37-15(a) specifies control requirements for storage tanks with a capacity above 40,000 gallons constructed after December 28, 1974. Such tanks shall be constructed with either (1) an external floating roof that consists of a pontoon type or double-deck type cover, or a fixed roof with an internal-floating cover; or (2) a vapor-recovery system that consists of a vapor-gathering system capable of collecting 85 percent or more of the uncontrolled VOCs; or (3) other equipment or methods that of equal efficiency and approved by the Division Director prior to installation. The permit requires compliance with OAC 252:100-37-15(a), except for petroleum or condensate stored, processed and/or treated at a drilling or production facility prior to lease custody transfer and except for methanol stored at drilling or production facilities, which is exempt per OAC 252:100-37-4(b).

Any VOC emissions from a storage vessel that are recovered and routed to a process through a VRU designed and operated as specified in §60.5365(e) are not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status. A properly installed and operated VRU is considered to recover 100% of the VOC emissions during the time the VRU is in use.

| Maximum Allowed Control Efficiency | Requirements |
|---|---|
| **Control Device : Flares or enclosed combustion device** | |
| ≤ 98% for VOC's, HAP's and $H_2S$ | • Meet 40 CFR §60.18 requirements for minimum heating value and maximum flare tip velocities<br>• Be operated with a flame present at all times by having a continuous pilot flame or an automatic ignition system<br>▪ Presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame, and<br>▪ Records of the pilot flame(s) outages and/or flare downtime shall be maintained<br>• Monitors must be accurate to and calibrated at the frequency in accordance with manufacturers specifications<br>• Be designed for the variability of the waste gas stream it controls |

The permit requires compliance with 40 CFR 60.18 for any applicable flares used to control equipment subject to an NSPS or NESHAP. Acid gas flares are required to meet the requirements of OAC 252:100-31-26 and a minimum heat content of 300 BTU/SCF.

The permit requires that condensers be properly operated, constructed with a temperature sensor in the outlet, and designed to achieve the expected removal efficiency at the maximum expected condenser outlet temperature, unless all vapor from the condenser is combusted or recycled to the process.

| Maximum Allowed Control Efficiency | Requirements |
|---|---|
| **Control Device : Condenser** | |
| ≤ 90% for VOC's and HAP's | • Have exhaust temperature monitored at the outlet of the condenser<br>▪ Exhaust temperature at 120° for a max efficiency of 90%<br>▪ Monitored exhaust temperature monthly<br>• Must be maintained and operated as specified by the manufactured or design engineering.<br>• Not followed by further control such as reboilers, flares, or glowplugs. If such controls are installed, greater than 90% destruction may be applied if meeting the device requirements of the control selected. |

| Maximum Allowed Control Efficiency | Requirements |
|---|---|
| **Control Device : Combustion device such as reboiler or heater** | |
| ≤ 50% for VOC's and HAP's | • Have waste gas delivered to the flame zone/firebox |
| < 98% for VOC's and HAP's | • Must meet requirements to claim 90% destruction efficiency as described by the condenser table and<br>• Have the waste gas pre-mixed with the primary fuel gas and used to fuel the device or<br>• Routed to the facility inlet<br>or<br>• Utilize a glow plug and maintain per operators/manufacturer's instructions |

The permit requires that nonselective catalytic reduction (NSCR) systems be constructed with an air-to-fuel ratio controller (AFRC) that operates on exhaust oxygen sensor control and with a sensor to measure the inlet temperature to the catalyst. The permit requires that oxidation catalyst systems be constructed, at a minimum, with a sensor to measure the inlet temperature to the catalyst. The permit must incorporate a CO lb/hr limit and require monitoring of carbon monoxide (CO) as a surrogate to assure compliance of $H_2CO$. Limit shall be based on manufacturer's uncontrolled CO emissions guarantee at 100% load reduced at an equal control rate as requested for $H_2CO$, not to exceed 90%. Any units subject to federal required monitoring are exempt from these requirements.

| Maximum Allowed Control Efficiency | Requirements |
|---|---|
| **Control Device : Catalytic converters** | |
| Manufacture guarantee as stated in application (Not to exceed 90%) | • Use a portable analyzer to monitor nitrogen oxides, CO and oxygen concentration in the exhaust stream of the control device.<br>▪ The portable analyzer shall be operated in accordance with the requirements of the latest AQD "Portable Analyzer Guidance" document or an equivalent method approved by the AQD.<br>▪ Testing shall be performed quarterly<br>• Monitoring device shall be installed to record the inlet flue gas temperature to the catalyst and be measured at least once daily.<br>▪ Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or other written procedures that provide an adequate assurance that the device is calibrated accurately. |

| Maximum Allowed Control Efficiency | Requirements |
|---|---|
| **Control Device : Oxidation Catalysts** | |
| $H_2CO$ reduction = CO reduction (Not to exceed 90%) | • Meet requirements listed above for catalytic converters. |

## SECTION IX. TIER CLASSIFICATION AND PUBLIC REVIEW

Processing of a new, modified, or renewed General Permit has been classified as Tier II based on OAC 252:2-15-41(c)(1). A request for an Authorization under this General Permit will typically be classified as Tier I, unless a compliance schedule required by OAC 252:100-8-5(e)(8)(B) is included, in which case it will be classified as Tier II.

A public notice of a 30-day public review period for the draft permit will be published in *The Tulsa World* and in *The Oklahoman*. A copy of the draft permit will be available for review at the Main Office of the Oklahoma Department of Environment Quality, 707 N. Robinson in Oklahoma City and in the Air Quality Section of the DEQ web page: *www.deq.state.ok.us*.

## SECTION X. SUMMARY

Applicants must demonstrate eligibility for coverage under this General Permit and that they are able to comply with applicable air quality rules and regulations. Ambient air quality standards are not threatened at any of the sites eligible for coverage under this General Permit. Issuance of the permit is recommended.

# APPENDIX A

## Justification to Document Compliance with OAC 252:100-31 for $H_2S$ Amine Units and Fuel Burning Equipment

## SECTION I. INTRODUCTION

AERSCREEN (11126) was used to conduct modeling to determine compliance with the ambient standard for $H_2S$ of OAC 252:100-31-7 for amine units, engines, and heaters/boilers. The ambient air quality standard is shown below.

> **252:100-31-7. Allowable hydrogen sulfide ($H_2S$) ambient air concentrations for new and existing sources**
> (b) **Hydrogen sulfide.** Emissions of $H_2S$ from any facility shall not cause an ambient air concentration of $H_2S$ greater than 0.2 ppm at standard conditions, 24-hour average.
> (c) **Exceptions.** The standards set in this section shall not apply to ambient air concentrations or impacts occurring on the property from which such emission occurs, providing such property, from the emission point to the point of any such concentration, is controlled by the person responsible for such emission.

Each section identifies the type of source being modeled, the description of the specific scenario, and the individual cases within each scenario. The source data used in the AERSCREEN modeling was based on information obtained from AQD's Emission Inventory database. Each of the modeling scenarios and cases were modeled in three locations which were determined to be representative of the varying terrain in the State of Oklahoma. For information related to the locations, development of each scenario, source type, or modeling input parameters, refer to the background information document entitled *GP-OGF Modeling of $H_2S$ Sources* dated May 13, 2014.

## SECTION II. AMINE UNITS

The AERSCREEN modeling conducted to determine compliance with OAC 252:100-31 was based on the following two (2) scenarios:

- Amine unit still vents with $H_2S$ emission less than or equal to 0.3 lb/hr, and vented directly to the atmosphere without controls. Two cases for this scenario were developed related to amine units with the still vent routed directly to the atmosphere.
    - The first case is a facility which treats sweet natural gas (less than or equal to 4 ppmv $H_2S$).
    - The second case is a facility which treats sour natural gas (greater than 4 ppmv $H_2S$).

- Amine unit still vents with $H_2S$ emission greater than 0.3 lb/hr, and flared (oxidized). Two cases were also developed for this scenario.

- The first case is based on the de minimis level of $H_2S$ emissions 0.3 lb/hr being flared, assuming 95% control (0.015 lb/hr $H_2S$).
- The second case is based on the maximum amount of $SO_2$ emissions for a minor source or the major source threshold. Assuming 95% control and 99 TPY (23.79 lb/hr) $SO_2$, this is equivalent to uncontrolled $H_2S$ emissions of 0.63 lb/hr.

**AERSCREEN Amine Unit Modeling Scenario 1**

Scenario 1 represents AERSCREEN modeling for amine unit still vents with $H_2S$ emissions routed directly to the atmosphere with emissions of less than 0.3 lb/hr. The first case represents a facility with an amine unit which is used to treat sweet natural gas (less than or equal to 4 ppmv $H_2S$). The second case represents a facility with an amine unit which is used to treat sour natural gas (greater than 4 ppmv $H_2S$).

**Scenario 1 AERSCREEN Input Parameters**

| Source Parameters | Case 1 | Case 2 |
|---|---|---|
| Type | Point | Point |
| Emission Rate (lb/hr) | 0.3 | 0.3 |
| Stack Height (ft) | 10 | 10 |
| Stack Diameter (ft) | 0.5 | 0.33 |
| Stack Flow (ACFM) | 332 | 133 |
| Stack Velocity (ft/s) | 29 | 26 |
| Stack Temperature (°F) | 100 | 100 |

The following table shows the AERSCREEN results for each of the Scenario 1 cases at each of the three locations.

**Scenario 1 AERSCREEN Results**

| Location 1 | Case 1 | Case 2 |
|---|---|---|
| 24-hr Concentration ($\mu g/m^3$) | 242.3 | 290.4 |
| Distance From Source (m) | 18.0 | 16.0 |
| **Location 2** | **Case 1** | **Case 2** |
| 24-hr Concentration ($\mu g/m^3$) | 191.9 | 213.4 |
| Distance From Source (m) | 23.0 | 21.0 |
| **Location 3** | **Case 1** | **Case 2** |
| 24-hr Concentration ($\mu g/m^3$) | 198.7 | 231.4 |
| Distance From Source (m) | 20.0 | 23.0 |

The maximum modeled concentration for Case 1 is below the 0.2 ppm (283 $\mu g/m^3$) ambient air concentration limit. However, the maximum modeled concentration for Case 2 does exceed the 0.2 ppm (283 $\mu g/m^3$) ambient air concentration limit. Therefore, the general permit will exclude those facilities with uncontrolled amine units that process sour natural gas (> 4 ppmv $H_2S$).

**AERSCREEN Amine Unit Modeling Scenario 2**

Scenario 2 represents AERSCREEN modeling for amine unit still vents with $H_2S$ emissions routed to a flare for oxidation assuming 95% control. The first case is based on an $H_2S$ emission rate of 0.3 lb/hr before being flared. The second case is based on the major source threshold of 99 TPY (0.63 lb/hr) $SO_2$.

**Scenario 2 AERSCREEN Input Parameters**

| Source Parameters | Case 1 | Case 2 |
|---|---|---|
| Type | Flare | Flare |
| Emission Rate (lb/hr) | 0.015 | 0.63 |
| Stack Height (ft) | 25 | 25 |
| Waste Gas Heat Content (BTUH) | 1,127,658 | 135,788 |

The following table shows the AERSCREEN results for Scenario 2 at each of the three locations.

**Scenario 2 AERSCREEN Results**

| Location 1 | Case 1 | Case 2 |
|---|---|---|
| 24-hr Concentration ($\mu g/m^3$) | 1.0 | 154.5 |
| Distance From Source (m) | 232.0 | 180.0 |
| **Location 2** | **Case 1** | **Case 2** |
| 24-hr Concentration ($\mu g/m^3$) | 0.2 | 38.2 |
| Distance From Source (m) | 95.0 | 517.0 |
| **Location 3** | **Case 1** | **Case 2** |
| 24-hr Concentration ($\mu g/m^3$) | 0.2 | 31.4 |
| Distance From Source (m) | 82.0 | 533.0 |

The maximum modeled concentration for both cases is below the 0.2 ppm (283 $\mu g/m^3$) ambient air concentration limit.

## SECTION III. ENGINES

The General Permit limits the sulfur content of fuel gas for engines to 162 ppmv. Therefore, this modeling scenario represents engines combusting fuel gas with an $H_2S$ content of 162 ppmv and a combustion efficiency of 99%, which results in an emission factor of $3.02 \times 10^{-4}$ lb/MMBTU. Three cases were developed for modeling small engines with a stack diameter of less than 1 foot, medium engines with a stack diameter equal to one foot, and large engines with a stack diameter greater than 1 foot.

**Engine Specifications**

| Source Parameters | Case 1 | Case 2 | Case 3 |
|---|---|---|---|
| Make | Arrow | White Superior | Cooper Bessemer |
| Model | VRG330 | 8G825 | GMVA-10 |
| Horsepower (Hp) | 68 | 800 | 2,400 |
| Heat Input (BTU/hp-hr) | 7,300 | 7,750 | 8,000 |
| MMBTUH | 0.50 | 6.20 | 19.2 |

**Engine AERSCREEN Input Parameters**

| Source Parameters | Case 1 | Case 2 | Case 3 |
|---|---|---|---|
| Type | Point | Point | Point |
| Emission Rate (lb/hr) | $1.51 \times 10^{-4}$ | $1.87 \times 10^{-3}$ | $5.80 \times 10^{-3}$ |
| Stack Height (ft) | 7.0 | 10 | 15 |
| Stack Diameter (ft) | 0.33 | 1.0 | 1.5 |
| Stack Flow (ACFM) | 238 | 3,738 | 8,263 |
| Stack Velocity (ft/s) | 45 | 79 | 78 |
| Stack Temperature (°F) | 970 | 1,340 | 825 |

The following table shows the AERSCREEN results for each engine modeling case at each of the three locations.

**Engine AERSCREEN Results**

| Location 1 | Case 1 | Case 2 | Case 3 |
|---|---|---|---|
| 24-hr Concentration ($\mu g/m^3$) | $2.54 \times 10^{-2}$ | $8.01 \times 10^{-2}$ | $1.27 \times 10^{-1}$ |
| Distance From Source (m) | 20.0 | 18.0 | 285.00 |
| **Location 2** | **Case 1** | **Case 2** | **Case 3** |
| 24-hr Concentration ($\mu g/m^3$) | $3.29 \times 10^{-2}$ | $9.12 \times 10^{-2}$ | $1.15 \times 10^{-1}$ |
| Distance From Source (m) | 19.0 | 28.0 | 46.0 |
| **Location 3** | **Case 1** | **Case 2** | **Case 3** |
| 24-hr Concentration ($\mu g/m^3$) | $3.13 \times 10^{-2}$ | $9.86 \times 10^{-2}$ | $1.22 \times 10^{-1}$ |
| Distance From Source (m) | 25.0 | 24.0 | 41.0 |

The modeling results for the engines are all less than 1% of the standard; therefore, all engines combusting fuel with a sulfur content less than 162 ppmv are in compliance with the ambient air concentration limit.

## SECTION IV. HEATERS AND BOILERS

The General Permit also limits the sulfur content of the fuel gas for heaters and boilers to 162 ppmv. Therefore, this modeling scenario represents heaters/boilers combusting fuel gas with an $H_2S$ content of 162 ppmv and a combustion efficiency of 95%, which results in an emission factor of $1.51 \times 10^{-3}$ lb/MMBTU. Three cases were developed for modeling heaters/boilers with a heat input less than 1 MMBTUH, heaters/boilers with a heat input greater than or equal to 1 MMBTUH, and heaters/boilers with a heat input greater than or equal to 10 MMBTUH.

**Heater/Boiler Specifications**

| Source Parameters | Case 1 | Case 2 | Case 3 |
|---|---|---|---|
| MMBTUH | 0.50 | 3.20 | 21.0 |

**Heater/Boiler AERSCREEN Input Parameters**

| Source Parameters | Case 1 | Case 2 | Case 3 |
|---|---|---|---|
| Type | Point | Point | Point |
| Emission Rate (lb/hr) | $7.55 \times 10^{-4}$ | $4.83 \times 10^{-3}$ | $3.17 \times 10^{-2}$ |
| Stack Height (ft) | 8.0 | 21.9 | 33.0 |
| Stack Diameter (ft) | 0.50 | 1.30 | 2.30 |
| Stack Flow (ACFM) | 168 | 1,072 | 7,038 |
| Stack Velocity (ft/s) | 14 | 13 | 28 |
| Stack Temperature (°F) | 370 | 370 | 370 |

The following table shows the AERSCREEN results for each heater/boiler modeling case at each of the three locations.

**Heater/Boiler AERSCREEN Results**

| Location 1 | Case 1 | Case 2 | Case 3 |
|---|---|---|---|
| 24-hr Concentration (μg/m$^3$) | 0.20 | 0.42 | 0.88 |
| Distance From Source (m) | 176.0 | 230.0 | 277.0 |
| **Location 2** | **Case 1** | **Case 2** | **Case 3** |
| 24-hr Concentration (μg/m$^3$) | 0.19 | 0.13 | 0.23 |
| Distance From Source (m) | 20.0 | 56.0 | 83.0 |
| **Location 3** | **Case 1** | **Case 2** | **Case 3** |
| 24-hr Concentration (μg/m$^3$) | 0.21 | 0.14 | 0.23 |
| Distance From Source (m) | 17.0 | 52.0 | 76.0 |

The modeling results for heater/boilers are all less than 1% of the standard; therefore, all heaters/boilers combusting fuel with a sulfur content less than 162 ppmv are in compliance with the ambient air concentration limit.

## SECTION V. SUMMARY

### Amine Units

Uncontrolled amine units with their still vents routed directly to the atmosphere have a potential to exceed the OAC 252:100-31-7 $H_2S$ ambient air concentration limit of 0.2 ppm (283 μg/m$^3$). Based on Scenario 1, Case 2, outlined in Section II of this appendix, the general permit shall exclude uncontrolled amine units that treat sour natural gas (> 4 ppmv $H_2S$).

Amine units with their still vents routed to a flare are unlikely to exceed the OAC 252:100-31-7 $H_2S$ ambient air concentration limit of 0.2 ppm (283 μg/m$^3$). Therefore, no specific limits need to be established in the general permit for amine units that route their still vents to a flare.

In order to ensure that only uncontrolled amine units that treat sweet natural gas are permitted under the general permit, the General Permit incorporates a limit of less than or equal to 4 ppmv $H_2S$ in the inlet gas for uncontrolled amine units. Facilities with amine units treating sour natural gas (> 4 ppmv $H_2S$) may be eligible for coverage under an Authorization to Operate if they first

obtain an individual minor source construction permit, where all relevant requirements and limitations demonstrate compliance with the $H_2S$ ambient air concentration limit in OAC 252:100-31-7.

The general permit also incorporates monitoring and recordkeeping of the inlet $H_2S$ concentration at least quarterly to ensure compliance with this limit. Controlled (flared) amine units are required to maintain these records for emission calculations.

**Engines**

Engines combusting fuel with a sulfur content less than 162 ppmv are unlikely to exceed the 0.2 ppm $H_2S$ ambient air concentration limit in OAC 252:100-31-7. A fuel sulfur limit of 162 ppmv will ensure compliance with the ambient air concentration limit in OAC 252:100-31-7.

**Heaters/Boilers**

Heaters/boilers combusting fuel with a sulfur content less than 162 ppmv are unlikely to exceed the 0.2 ppm $H_2S$ ambient air concentration limit in OAC 252:100-31-7. A fuel sulfur limit of 162 ppmv will ensure compliance with the ambient air concentration limit in OAC 252:100-31-7.

**Facility Wide Compliance**

The $H_2S$ ambient air concentration of OAC 252:100-31-7 is applicable to each facility as a whole. Since most facilities will not have multiple amine units and the impacts from engines and heaters/boilers is so low, even if a facility was to be equipped with an amine unit and multiple engines and heaters/boilers, the facility as a whole would still be in compliance with the $H_2S$ ambient air concentration limit.

Facilities with more than one uncontrolled amine unit treating sweet natural gas ($\leq$ 4 ppmv $H_2S$) could potentially exceed the $H_2S$ ambient air concentration limit of 0.2 ppm. Therefore, facilities with more than one uncontrolled amine unit may be eligible for coverage under an Authorization to Operate if they first obtain an individual minor source construction permit, where all relevant requirements and limitations demonstrate compliance with the $H_2S$ ambient air concentration limit in OAC 252:100-31-7.