FACT SHEET

TITLE V OIL & GAS FACILITIES

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WHAT IS TITLE V?

Title V of the Federal Clean Air Act Amendments of 1990 (CAAA) required development of permit programs that would require major sources of air emissions throughout the U.S. to obtain an operating permit. These operating permits are referred to as "Title V permits," or "Part 70 permits" since EPA issued rules for State Title V Programs under 40 CFR, Part 70. The Oklahoma Department of Environmental Quality (DEQ) has obtained authority and approval from EPA to administer the program for Oklahoma, effective March 6, 1996. Oklahoma received approval to implement a 3-year phased application submittal schedule, with all permits to be issued within five years. Although Oklahoma has required an operating permit for both major and minor sources for a number of years, Title V requires all existing major facilities to submit an application for a new Title V operating permit during this three-year phase-in. *A separate DEQ Title V Program Fact Sheet is available, which gives more details on the program.*

AM I A TITLE V SOURCE?

In general, a Part 70 permit is required of those facilities with the potential-to-emit (PTE) of 100 TPY or more of any criteria pollutant (NO_x, CO, SO_2, Ozone (as VOCs), PM_{10}, and Lead), or 10 TPY or more of any one Hazardous Air Pollutant (HAP), or 25 TPY or more of any combination of HAPs. If prior to the facility's Title V application submittal deadline a facility has applied for a minor permit which would limit emissions below the threshold levels mentioned above (i.e., by requiring operational constraints and/or control equipment), a Part 70 permit would not be required. Otherwise, PTE is calculated as if no air pollution control equipment is in place and all operations are continuous. Facilities in the Oil and Gas industry have the potential to emit several criteria pollutants and HAPs. An emissions inventory should be performed at your facility to determine if you exceed any of the Title V thresholds. *Please see the DEQ Fact Sheet on PTE for the general process in calculating PTE, or the attached example for gas compression and dehydration stations.*

Certain other sources, e.g., any affected source subject to the Acid Rain Rules, and any solid waste incinerator subject to Section 129(e) of the CAA, are required to obtain a Part 70 permit regardless of their PTE. In addition, sources subject to an NSPS or NESHAP would have to obtain a Part 70 permit **only** if the subpart specifically required them to do so. Note that at this time, no Oil & Gas facilities are currently required to obtain a Part 70 permit specifically because of an NSPS.

Several NESHAPs may be applicable now to operations at Oil & Gas facilities. In addition, several NESHAPs are scheduled for promulgation in the near future which may also be applicable to these operations. Those NESHAPs currently effective include:

Source Category	Promulgation Date	40 CFR 61 Subpart
Equipment Leaks (Benzene)	6/6/84	Subpart J
Equipment Leaks	6/6/84	Subpart V

Source Category	Promulgation Date	40 CFR 63 Subpart
Petroleum Refineries	8/18/95	Subpart CC
Gasoline Distribution Facilities	12/14/94	Subpart R
Hazardous Organic NESHAP	4/22/94	Subpart F, G, H, I
Degrease Organic Cleaners*	12/02/94	Subpart T
Off-site Waste Treatment	7/01/96	Subpart DD
Industrial Cooling Towers**	9/08/94	Subpart Q

*Applies to major sources as well as area sources. However, applicability to area sources has been deferred until December 9, 1999. Title V applications for deferred area sources are due by December 9, 2000.
**Applies to those cooling towers using chromium compounds.

Those NESHAPs scheduled for promulgation in the future that may potentially affect operations at Oil & Gas facilities include:

Source Category	Promulgation Date
Oil & Natural Gas Production	11/15/97
Petroleum Refineries	11/15/97
Industrial Boilers	11/15/00
Process Heaters	11/15/00
Stationary IC Engines	11/15/00
Stationary Turbines	11/15/00

Note that most NESHAPs apply only to major sources. However, there are some that apply to area (minor) sources as well as major sources. In particular, the Halogenated Solvent Cleaning NESHAP applies to both major and minor sources. However, this NESHAP has been deferred until December 9, 1999, with Title V applications due by December 9, 2000. The Halogenated Solvent Cleaning NESHAP applies to certain solvent cleaning sources using methylene chloride, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, carbon tetrachloride, or chloroform at both major and minor source facilities.

Use of a solvent cleaner subject to this NESHAP could require a Part 70 permit for the entire facility, even if it is a minor source (see the specific NESHAP for more details). Note that NESHAPs require an initial notification of NESHAP status. In lieu of this notification, a facility may submit an application for a Part 70 permit. Depending on the notification date, and your Title V submittal date, you may want to submit a Title V application in lieu of the NESHAP notification.

NSPS SUBPARTS OF CONCERN & EFFECTIVE DATES

Subpart K:	Storage Vessels for Petroleum Liquids (between June 11, 1973, and May 19, 1978)
Subpart Ka:	Storage Vessels for Petroleum Liquids (between May 18, 1978, and July 23, 1984)
Subpart Kb:	Storage Vessels for Volatile Organic Liquids, (Including Petroleum Liquids), (after July 23, 1984)
Subpart GG:	Stationary Gas Turbines (after October 3, 1977)
Subpart XX:	Bulk Gasoline Terminals (after December 17, 1980)
Subpart KKK:	Equipment Leaks of VOC from Onshore Natural Gas Processing Plants (after January 20, 1984)
Subpart LLL:	Onshore Natural Gas Processing; SO_2 Emissions (after January 20, 1984)

STATE RULES OF CONCERN

Subchapter 7:	New Source Permits (effective date: October 1972)
Subchapter 8:	Part 70 Permits (effective date: March 6, 1996)
Subchapter 9:	Excess Emissions Reporting (affects both new and existing)
Subchapter 10:	General Operating Permits for the Crude Petroleum and Natural Gas Industry (effective date: July 1, 1996)
Subchapter 19:	Particulate Matter Emissions from Fuel-burning Equipment (affects both new and existing)
Subchapter 25:	Smoke, Visible Emissions, and Particulates (affects both new and existing)
Subchapter 29:	Fugitive Dust (affects both new and existing)
Subchapter 31:	Sulfur Compounds (affects both new and existing)
Subchapter 33:	Nitrogen Oxides (effective date: October 1971)
Subchapter 37:	Organic Materials (affects both new and existing)
Subchapter 39:	Organic Materials (affects both new and existing units in Tulsa and Oklahoma Counties)
Subchapter 41:	Hazardous and Toxic Air Contaminants (affects both new and existing)

DO EXPLORATION & PRODUCTION SOURCES NEED A PART 70 PERMIT?

Air emissions or potential for air emissions required or requested to be permitted under the Clean Air Act are under the jurisdiction of the DEQ. All sources of air emissions of regulated pollutants from oil and gas exploration and production which are less than Title V major source thresholds are the jurisdiction of the Oklahoma Corporation Commission (OCC), except those which may be covered by NSPS, NESHAPs, PSD, or other applicable federal regulations requiring an air quality permit.

Any source under OCC jurisdiction that elects to submit a permit application or applicability determination request to DEQ may do so.

Typical exploration and production equipment with emissions of criteria or hazardous air pollutants include the following:

Tanks and Vessels
- -hydrocarbon
- -non-fired separators
- -produced water

External Combustion Sources
- -line heaters
- -heater treaters
- -glycol dehydrator burners
- -incinerators
- -boilers

Internal Combustion Engines
(reciprocating or turbine)
- -compressors
- -pumps
- -generators
- -pumping units

Tank Truck Loading

Fugitive Sources
- -valves
- -flanges
- -compressor seals
- -threaded fittings
- -relief valves

Flares

Glycol Dehydrator Reboiler Vents

Sulfur Recovery Unit
- -sulfur removal units

Miscellaneous
- -sump tanks
- -waste water ponds
- -bleed-type controllers
- -cooling towers
- -vents not included above

Each of these emission sources would be included or exempt from DEQ jurisdiction and the concurrent Title V permitting process based not on the type of source, but rather on the emission rate.

WHAT PERMITTING OPTIONS ARE AVAILABLE?

If you are a true minor source, i.e., your PTE is less than Title V thresholds, under DEQ jurisdiction you are still required to have a DEQ-issued minor-source operating permit if emissions of any criteria pollutant exceed 1 lb/hr, or if emissions of any toxic air pollutant exceed the de minimis level given in DEQ rules (OAC 252:100-41-43). If your PTE exceeds Title V thresholds, but you are able to limit emissions to below those thresholds you may be eligible for a "synthetic minor" permit. In general, permit limitations on PTE in a synthetic minor permit must be federally enforceable. *See the DEQ Fact Sheet on PTE for more details*. If you cannot, or chose not to limit your PTE to below Title V thresholds, then you are required to apply for a Part 70 permit by the submittal schedule deadline for your particular type of facility. Those petroleum and natural gas facilities whose SIC codes include

1311 (Petroleum and Natural Gas), 1321 (Natural Gas Liquids), 4922 (Natural Gas Transmission), or 4923 (Natural Gas Transmission & Distribution), may be eligible for coverage under the General Operating Permit for Crude Petroleum and Natural Gas Facilities (GOP). The GOP is a streamlined Part 70 permit with pre-determined equipment criteria and emission limitations, and a simplified issuance process.

WHEN ARE TITLE V APPLICATIONS DUE?

DEQ has received approval to implement a three year phased submittal schedule with all permits to be issued after five years. The effective date for this schedule is March 6, 1996. The first group of applications for oil and gas facilities include one third of all petroleum and natural gas (SIC 1311), natural gas liquids (SIC 1321), natural gas transmission (SIC 4922), natural gas transmission and distribution (SIC 4923), and petroleum bulk stations and terminals (SIC 5171). Applications for this first group were due by September 5, 1996. The second group includes the remaining two thirds of the first group. Applications for the second group are due by March 5, 1997. The third group includes refineries (SIC 2911), and petroleum transportation/terminals/storage facilities (SIC 4612 & 4613). Applications for the third group are due by July 5, 1998. The final group includes all remaining sources and those applications are due by March 5, 1999.

WHERE DO I APPLY FOR A PERMIT?

Contact our office and we will send you the appropriate forms. If you are unsure as to whether you need a permit you should request an Applicability Determination (AD). An AD is used to determine whether a particular source or operation is subject to the requirements of a rule. The AD fee is $100 and, generally, must contain the same information as a regular permit application. In addition, you may contact the Customer Assistance Program or Air Quality Division and request a pre-application submittal conference. Staff will meet with you to identify any areas needing further work. The easiest way to expedite issuance of your Part 70 permit is to ensure that the application is administratively and technically complete. Requests for forms may be sent to:

DEQ
Air Quality Division
707 N. Robinson, Suite 4100
P.O. Box 1677
Oklahoma City, OK 73101-1677

DEQ
Customer Assistance Program
1000 N. E. 10th Street
Oklahoma City, OK 73117-1212

WHO CAN I CONTACT FOR MORE INFORMATION?

For general assistance contact our Customer Service Division, toll free at 1-800-869-1400, or for specific assistance contact the Air Quality Division at (405) 702-4100.

Example problem: Gas compression and dehydration station

Stationary source description:

(3) 1200 horsepower engines for compression:

Engine #1 operating at 700 rpm
Engine #2 operating at 1200 rpm
Engine #3 operating at 1200 rpm

Dehy burner: 750 MBtu/hr
Flash Tank
Stripping gas: 18 scfm
Electric pump for T.E.G.
Dehydration processes 26 MMSCFD

Maximum operating conditions:

Stationary source Inlet:	Dehy Inlet:
Q = 26 MMSCFD	Q = 25.5 MMSCFD
P_{in} = 70 psig	P_{in} = 760 psig
T_{in} = 85 ^{o}F	T_{in} = 120 ^{o}F

Calculate potential-to-emit

T.E.G. dehydration unit

Dehydrator potential-to-emit is defined by operation of the unit. By definition, potential-to-emit is the emission level that will occur at the maximum design capacity of the stationary source.

Possible methods of defining gas processing plant potential-to-emit:

Maximum throughput of compressors to define plant processing capability.

> Consider max. inlet pressure; min. inlet temp; min. outlet press; max. compressor rpm. Some of these parameters may be contract requirements while others may have been stipulated in the construction permit.

Maximum BTEX and/or VOC content of gas stream.

> Consider the stability of gas composition, contract limits on sales gas water content. Estimate emissions using GLYcalc program.

Maximum heat duty of regeneration equipment.

Consider water content of gas; sales gas water content; max. lean glycol recirculation ratio; %water in lean glycol (to determine stripping gas rate); max. temperature; and stable gas composition.

Maximum circulation rate of glycol pumps.

Consider gas composition; material balance of emissions between rich and lean glycol samples. This method may require additional evaluation of VOC content in glycol from flash tank and reboiler.

Potential-to-emit for T.E.G. dehydration unit using GRI's GLYCalc program

Gas Research Institute has developed a program to estimate the emissions from a glycol (T.E.G. or E.G.) regeneration unit. The results of the program have been found acceptable by the EPA. Another method of determining HAP potential-to-emit would be the material balance calculation comparing BTEX and n-C6 content from rich and lean glycol samples. To use the GRI-GLYCalc program, the following information is needed:

Gas composition AT DEHY INLET

Component	Vol %	Component (cont'd)	Vol %
$C0_2$	0.032	other C6s	0.0190
H_2S	0.000	C7s	0.0600
N_2	14.97	2,2,4 Trimethylpentane	0.000
C1	72.75	Benzene	0.0002
C2	6.181	Toluene	0.0001
C3	3.836	Xylenes	0.0000
C4s	1.562	C8+	0.0140
C5s	0.4759		
n-C6	0.083		

Other GRI-GLYCalc input for maximum throughput conditions:

Gas is saturated	Yes
Lean glycol recirc. ratio of	3.00 gals/lb H_20
Type of stripping gas	dry gas
Stripping gas flow rate:	18 scfm
Dry gas dewpoint:	7 lbs. H20/MMSCF
Lean glycol concentration:	99.95% T.E.G.
Flash tank op. Conditions:	60 psi, 110 ^oF

Output: GRI-GLYCalc estimated air emissions

Glycol Type:	T.E.G.
Annual Hours of Operation:	8,760 hrs
Dry Gas Flow Rate:	25.5 MMSCF/day
Wet Gas is saturated with water:	Yes
Calculated Wet Gas Water	129 lbs H_20/MMSCF
Specified Dry Gas Dew Point:	7.00 lbs H_20/MMSCF
Calculated Absorber Stages:	1.69
Specified Lean Glycol Recirc.:	3.00 gals/lb H_20
Glycol Losses Down Pipe:	0.0681 lbs/hr
Glycol Pump Type:	Gas Driven
Recirc. Pump:	Electric
Regenerator Stripping Gas:	Dry Product Gas
Stripping Gas Flow Rate:	18 scfm

Uncontrolled regenerator emissions

Component	lbs/hr	lbs/day	tons/yr
n-Hexane	1.52	33.4	6.64
Benzene	0.0591	1.42	0.259
Toluene	0.0528	1.27	0.231
Total H-C Emissions	58.4	1401	256
Total VOC Emissions	19.0	457	83.4
Total HAP Emissions	1.63	39.0	7.13
Total BTEX Emissions	0.112	2.68	0.490

Flash tank offgas emissions

Component	lbs/hr	lbs/day	tons/yr
n-Hexane	0.300	7.19	1.31
Benzene	0.0008	0.020	0.0037
Toluene	0.0004	0.010	0.0018
Total H-C Emissions	19.5	468	85.4
Total VOC Emissions	8.49	204	37.2
Total HAP Emissions	0.301	7.22	1.32
Total BTEX Emissions	0.0012	0.030	0.0055

Dehydration unit total emissions

Pollutant	**Tons/yr**
n-Hexane	7.95
Benzene	.263
Toluene	.233
Ethyl-Xylene	0.0
Xylene	0.0
Total BTEX Emissions	.496
Total HAP Emissions	8.45
Total VOC Emissions	121

<u>Potential-to-emit for dehy regenerator heater</u>

The dehy regenerator is used to heat the rich glycol to 380+ degrees to boil off the water content of the glycol. The burner on the regenerator is thermostatically controlled to maintain a relatively constant temperature. However, for potential-to-emit calculations, the nameplate capacity of the burner is used with 8,760 hours per year of operation.

Using the nameplate design capacity for the regenerator potential-to-emit calculation:

Nameplate Reboiler Heat Duty: 750 MBtu/hr

AP-42 Factor for external fired natural gas boiler:

Units: million cubic feet, (MMSCF), burned

	$PM=PM_{10}$	SO_2	NOx	VOC	CO	Lead
	Lbs/unit	Lbs/unit	Lbs/unit	Lbs/unit	Lbs/unit	Lbs/unit
Nat. Gas	3	.6	100	5	20	---

Dehy potential-to-emit regenerator calculations:

Calculate quantity of fuel used:

$$750\ \frac{MBtu}{hr} \times \frac{MSCF}{1047\ MBtu} \times \frac{MMSCF}{10^3\ MSCF} = 7.16\text{x}10^{-4}\ \frac{MMSCF}{hr}$$

Calculate emissions for each pollutant:

$$3.0\ \frac{Lbs\ of\ PM}{MMSCF} \times 7.16\text{x}10^{-4}\ \frac{MMSCF}{hr} \times 8760\ \frac{hrs}{yr} \times \frac{1\ ton}{2000\ Lbs} = 0.0094\ \frac{tons}{year}$$

$$0.6\ \underline{Lbs\ of\ SO_x} \times 7.16\text{x}10^{-4}\ \underline{MMSCF} \times 8760\ \underline{hrs} \times \underline{1\ ton} = 0.0019\ \underline{tons}$$

MMSCF		***hr***		***yr***		**2000** ***Lbs***		***year***

100 ***Lbs of NO_x*** / ***MMSCF***	**x**	**$7.16x10^{-4}$** ***MMSCF*** / ***hr***	***x***	**8760** ***hrs*** / ***yr***	***x***	**1** ***ton*** / **2000** ***Lbs***	=	***0.314 tons*** / ***year***
5.0 ***Lbs of VOC*** / ***MMSCF***	**x**	**$7.16x10^{-4}$** ***MMSCF*** / ***hr***	***x***	**8760** ***hrs*** / ***yr***	***x***	**1** ***ton*** / **2000** ***Lbs***	=	***0.0157 tons*** / ***year***
20 ***Lbs of CO*** / ***MMSCF***	**x**	**$7.16x10^{-4}$** ***MMSCF*** / ***hr***	***x***	**8760** ***hrs*** / ***yr***	***x***	**1** ***ton*** / **2000** ***Lbs***	=	***0.0627 tons*** / ***year***

Summary of potential-to-emit from dehy regenerator

PM=PMIO	SO_2	NO_x	VOC	CO	Lead
tons/year	tons/year	tons/year	tons/year	tons/year	tons/year
0.0094	0.0019	0.314	0.0157	0.0627	---

Summary of pollutants *so far*....

Pollutant	**Tons/yr**	**Pollutant**	**Tons/yr**
n-Hexane	7.95	PM	0.0094
Benzene	.263	PM_{10}	0.0094
Toluene	.233	$S0_2$	0.0019
Ethyl-Xylene	0.0	NO_x	0.314
Xylene	0.0	CO	0.0627
Total BTEX Emissions	.496		
Total HAP Emissions	8.45		

Total VOC Emissions 121

Compressor engine equipment

Equipment description:

(3) 1200 horsepower engines for compression
Engine #1 operating at 700 rpm
Engine #2 operating at 1200 rpm
Engine #3 operating at 1200 rpm

Pollutants for emissions from engines are reported in different ways. AP-42 lists units in lbs/MMBtu while the various manufacturers' data generally lists emission factors in grams/hp-hr. Make sure units are used correctly in calculating potential-to-emit in tons per year.

Note that these are potential-to-emit calculations. By definition, this is the emission level that will occur at the maximum design capacity of the stationary source. Original construction permits often list the conditions at which an engine-compressor unit will be operated such as rpm, horsepower load, and air-fuel ratios. If conditions are listed in a previous permit, you may calculate potential-to-emit under the permitted conditions. However, to be used in the potential-to-emit calculations, the conditions must be "federally enforceable".

The table below lists the maximum continuous operating conditions for the given engines:

Engine	RPM @ max oper. conditions	Horsepower @ max. Continuous Load	Fuel Usage MMBtu/hr
Engine #l, (RB)	1200	907	6.84
Engine #2, (LB)	1200	1200	10.79
Engine #3, (LB)	1200	1085	8.17

Potential-to-emit calculation for each engine

From this data, with the conditions specified, the potential-to-emit for each engine is calculated:

Find appropriate emissions factors for the engines:

Manufacturer's Emission Factors, (grams/hp-hr)

	$S0_2$	NO_x	CO	VOC
Engine# 1 (RB)		7	28	0.3
Engine #2 (LB)		1.5	2.65	1.0

Engine #3 (LB)	1.94	1.2	0.5

SO_2 emission factor of 0.6 lbs/MMCF and PM_{10} factor of .003 grams/hp-hr are from AP-42 for natural gas fired internal combustion engines.

Knowing the horsepower and fuel for a given engine's operating conditions, the following calculations are made:

Engine #1 NO_x calculation:

$$907\ HP \times \frac{7\ \text{grams}}{\text{hp-hr}} \times \frac{8760\ \text{hrs}}{\text{year}} \times \frac{1\ \text{lb}}{454\ \text{grams}} \times \frac{1\ \text{ton}}{2000\ \text{Lbs}} = 61.3\ \frac{\text{tons}}{\text{year}}$$

Engine #1 SO_2 calculation using AP-42 factor:

$$6.84\ \frac{\text{MMBtu}}{\text{hr}} \times \frac{\text{MMCF}}{10^3\ \text{MMBtu}} \times \frac{0.6\ \text{Lbs}}{\text{MMCF}} \times \frac{8760\ \text{hrs}}{\text{year}} \times \frac{1\ \text{ton}}{2000\ \text{Lbs}} = 0.018\ \frac{\text{tons}}{\text{year}}$$

Compressor engine potential-to-emit calculation summary

Applying these equations for each pollutant, for each engine at maximum continuous operating conditions the results are as follows:

Units = tons/year

	NO_x	SO_2	CO	VOC	$PM=PM_{10}$
Engine #1 (rich burn)	61.3	0.018	245	2.63	0.026
Engine #2 (lean burn)	17.4	0.028	30.7	11.6	0.035
Engine #3 (lean burn)	20.3	0.022	12.6	5.23	0.031
Engine Totals	99.0	0.068	288	19.5	0.092

Potential-to-emit for gas compression station

Pollutant	Tons/yr	Pollutant	Tons/yr
n-Hexane	7.95	PM	0.101
Benzene	.263	PM10	0.101
Toluene	.233	S02	0.0699
Ethyl-Xylene	0.0	NOx	99.3
Xylene	0.0	CO	288

Total BTEX Emissions	.496
Total HAP Emissions	8.45
Total VOC Emissions	141

Note that emissions of HAPs do not exceed 10 TPY for any one HAP or 25 TPY for all HAPs. Thus, it isn't a major source for HAPs. However, emissions of CO exceed 100 TPY. Therefore, this facility is a major (Title V) source. If CO emissions from Engine #1 could be limited (by restricting hours of operations, installing control equipment, etc) to less than 56.7 TPY (100-30.7-12.6 TPY), this source would be considered a "synthetic minor" and thus would not be required to obtain a Part 70 permit.

Fugitive emissions calculations

When determining the necessity of a Title V permit, fugitive emissions must be considered when calculating potential-to-emit if the stationary source is a federally designated fugitive emission source as defined in OAC 252:100-8-3 (a)(1).

In addition to the 26 fugitive emission sources listed in OAC 252:100-8-3 (a)(1), certain NSPS source categories must include fugitive emission calculations.

If the emission source is within a source category that is regulated by an NSPS that was promulgated on or before August 7, 1980, then fugitive emissions from the emission source must be included when calculating potential-to-emit. However, fugitive emissions must be calculated only for those pollutants that are regulated by the NSPS for that source category.

For example, fugitive emissions of NO_x and $S0_2$ from gas turbines must be included in determining whether a stationary source is required to obtain a Title V permit. In this case, fugitives are included regardless of whether that particular gas turbine is subject to an NSPS. This is because an NSPS limiting NO_x and SO_x emissions from gas turbines was promulgated before August 7, 1980, (40 CFR Part 60, Subpart GG).

Remember that a fugitive emission is one that can't reasonably be collected and routed through a stack or vent (e.g., dust from roads, slag piles, and other such sources).

Title V Permit Application

Note that once it is determined that a Title V operating permit is needed, fugitive emissions are required to be reported in the Title V operating permit application even though fugitive emissions were not required to be included in the calculations to determine whether a Title V operating permit was needed.