

The Texas Commission on Environmental Quality (TCEQ or commission) proposes the repeal of §116.620.

The repeal would be submitted to the United States Environmental Protection Agency (EPA) as a revision to the state implementation plan (SIP).

#### BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULE

In concurrent actions, the commission is developing a new non-rule standard permit for the construction and modification of oil and gas facilities which will replace §116.620, Installation and/or Modification of Oil and Gas Facilities. These concurrent actions also include the proposed repeal of, and proposed new 30 TAC §106.352, Oil and Gas Production Facilities. The new permit by rule (PBR) and standard permit will provide an updated, comprehensive, and protective authorization for many common oil and gas sites (OGS) in Texas. The proposed PBR and standard permit will include operating specifications and emissions limitations for typical facilities and equipment during normal operation, which includes production and planned maintenance, start-up, and shutdown. The proposed PBR and standard permit will specifically address the appropriateness of multiple authorizations at one contiguous property and would reference the many new federal standards which have been promulgated by the EPA, as well as include revised criteria for registration and changes at existing, authorized sites. A more detailed discussion of the new proposed PBR is available in a separate section of this publication of the *Texas Register*.

#### SECTION DISCUSSION

*§116.620, Installation and/or Modification of Oil and Gas Facilities*

The commission proposes the repeal of this section which will be replaced by a non-rule standard permit for oil and gas facilities. This repeal will prevent conflicting authorization methods for the same types of facilities. Therefore, the commission proposes to withdraw §116.620 from consideration as part of the SIP.

#### FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT

Jeff Horvath, Analyst, Strategic Planning and Assessment Section, has determined that for the first five-year period the proposed rule is in effect, fiscal implications may be anticipated for the agency, but no fiscal implications are anticipated for other units of state or local government. The proposed action would repeal the current standard permit and PBR for oil and gas transportation and production facilities and propose a new non-rule standard permit and PBR that are more protective of human health, require consistency in facility authorization methods, and update control technology requirements. If facilities are authorized under the repealed standard permit, they must renew their standard permit registration under §116.604, Duration and Renewal of Registrations to Use Standard Permits, meet certain emission requirements by January 5, 2012, and comply with the requirements of the new standard permit if the registration is renewed after December 31, 2012. If they are authorized under the repealed PBR and are not modified, they may continue to be authorized under the current PBR. If a facility is modified, it must be re-authorized under the new PBR or under the proposed Air Quality Standard Permit for Oil and Gas Production Facilities which is being revised concurrently.

Currently, oil and gas production and transportation facilities are authorized by PBR, a standard permit, a case-by-case new source review (NSR) permit, or a combination of these authorizations. The proposed rule would repeal the current standard permit governing the operations of oil and gas facilities. An

additional and concurrent rule proposal would also repeal the current PBR governing the operations of oil and gas facilities. Upon repeal of the current PBR and standard permit, oil and gas facilities would be regulated under the provisions of a new non-rule standard permit and new PBR. Although current PBRs and standard permits are granted for a facility, under the new PBR and non-rule standard permit, facilities will be authorized under one permit for a single site. If the facility or group of facilities at the site cannot meet the requirements of the PBR or standard permit, they must be authorized under an NSR permit.

The provisions of the new PBR would allow oil and gas facilities to continue operations under their current PBR until a facility modification is made, or a new facility is constructed. Once one of these circumstances is met, oil and gas transportation and production facilities would have to apply for the new PBR or non-rule standard permit. If a non-rule standard permit is required, oil and gas transportation and production sites may incur permitting and operational costs to comply with its requirements. The proposed rule does not change the current fee rates for the non-rule standard permit nor the PBR.

If units of local government such as school districts or others own or operate oil and gas production or transportation facilities, they could be affected by the proposed rule. At this time, staff is not able to identify the number and type of local governments that may be affected, but there may be a limited number of local governments that own oil and gas production facilities. These governments would have the same compliance costs as privately owned businesses.

#### *Implications for Agency Revenue*

If a site currently operates under a PBR but has to obtain a new non-rule standard permit, the agency may see an increase in revenue. Staff estimates that on average, 1,000 PBRs are issued to oil and gas

transportation and production facilities on an annual basis. It is estimated that 50% of these, or 500 sites, may need to obtain a proposed new standard permit. The fee rate for a non-rule standard permit is \$900 and the current fee rate for a PBR is either \$100 for a small business or governmental entity or \$450 for all others. The estimated annual increase in revenue could be between \$225,000 and \$400,000 each year in Account 0151, Clean Air Account. Any increase in revenue would be offset by additional costs to various programs in the agency including Air Permits Division, Field Operations Division, and the Chief Engineers Office to implement the new requirements for the oil and gas industry.

#### PUBLIC BENEFITS AND COSTS

Mr. Horvath has also determined that for each year of the first five years the proposed rule is in effect, the public benefit anticipated from the changes seen in the proposed rule will be to ensure that emissions from affected facilities are protective of human health and that regulatory authorizations are more enforceable. The new authorizations will be more comprehensive to cover all operations located at oil and gas facilities.

In general, the proposed rule is not anticipated to result in significant fiscal implications for businesses or individuals as they would apply only to new or modified facilities.

#### *Increase in Permitting Costs*

The repeal of this standard permit will result in owners and operators of oil and gas facilities to re-register for the standard permit within two years of issuance. The following cost analysis is based on costs associated with the new non-rule standard permit. Modified or new oil and gas transportation and production sites will incur permitting and operational costs to obtain a new standard permit. A facility that

increases its emissions by 5 tons per year in volatile organic compounds (VOCs) or more than 0.1 tons per year in sulfur compounds would be subject to the new authorization requirements.

The new non-rule standard permit would classify a site as a Tier I or a Tier II site. Tier I sites will not be required to register or pay a permit fee. Tier II sites would pay \$900 for a new proposed standard permit. Staff estimates that approximately 500 oil and gas transportation and production sites currently operating under PBR will have to obtain a non-rule standard permit as Tier II sites. The increase in permit costs could be between \$225,000 and \$400,000 each year statewide.

#### *Increase in Permitting Costs*

Modified or new oil and gas transportation and production sites will incur permitting and operational costs to obtain a new non-rule standard permit or PBR. A facility that increases its emissions by 5 tons per year in VOCs or more than 0.1 tons per year in sulfur compounds would be subject to the new authorization requirements.

The new PBR would classify a site as a Level I or Level 2 site and both classifications would pay the standard fees for a PBR of \$450 or \$100 for a small business. Staff estimates that approximately 6,000 new and changing OGS will be required to submit a Level 1 post-construction registration (\$50-\$200) each year, and 3,000 new and changing OGS will be required to submit a Level 2 preconstruction registration (\$100-450) each year. In the past these OGS would not have required registration. In addition, staff estimates that 500 OGS currently operating under PBR will have to obtain a non-rule standard permit (\$900). The estimated annual increase in revenue could be between \$1,050,000 and \$3,000,000 each year statewide.

*Increase in Operating Costs*

If currently authorized sites are modified or if new facilities are constructed, various operational costs could be incurred if the required controls are not already in place.

Sites with fugitive components would have to be inspected and repaired to reduce fugitive emissions. Inspecting and repairing equipment with fugitive emissions is estimated to cost about \$1.25 per connection. A site with 20 to 25 connections could see monitoring costs for fugitive emissions range from \$25 to \$31 per year if this type of monitoring is not already taking place. Larger sites could have 1,000 or more connections, and the cost of monitoring fugitive emissions could exceed \$1,250 each year. The cost of monitoring fugitive emissions will vary from site to site depending on the number of connections, activity at the site, and the configuration of the site.

The new standard permit would require the sampling of gas streams with a cost of \$800 to \$1,200 per sample. Sites may require one to six samples yearly depending on the facilities installed. This gives a potential cost range of \$800 to \$7,200. The new PBR and non-rule standard permit would also require that glycol dehydrator regenerator vents be controlled at a minimum efficiency of 80% by weight. This would be achieved by a condenser and separator, a vapor recovery unit, a destruction device, or other equivalent devices. Costs of these devices could range from \$2,500 to \$5,000. Cost associated with the installation and operation of a vapor recovery unit would be partially offset through recovery of marketable product. The commission further estimates that the cost for new controls or procedures will apply to about 100,000 of the potentially affected OGS. This estimate is based on facilities having emissions of VOC below 5 tons per year and sulfur compounds below 0.1 tons per year.

The new standard permit could require future retrofitting of existing facilities to meet emissions limitations based on the distance of receptors from an OGS. The TCEQ would not be able to assess additional costs, if any, as the TCEQ will not be able to reasonably account for the courses of actions for existing OGS and will not be able to reasonably account for existing facilities that will meet the emissions limitations requirements without retrofitting. The following information provides a range of costs for individual equipment and operations required under this proposed rule. A site will incur these costs based on the equipment and operations at a specific site. Additionally, owners of an OGS have options for specific types of equipment to perform the same function. For example, generally only one type of thermal destruction device will be used, either a flare or a thermal oxidizer, or the owner/operator may choose to use a vapor recovery unit. The commission does not expect each site to incur all of these costs.

The new standard permit would require testing for emissions of total VOCs and formaldehyde from engines. This would be expected to increase the total cost of testing for engines and turbines from about \$2,000 to \$5,000 per test for VOC and formaldehyde in addition to already required testing.

The new standard permit would require testing for emissions of total VOCs and benzene from thermal oxidizers. This would cost a total of \$10,000 to \$20,000 for current testing (nitrogen oxide (NO<sub>x</sub>) and carbon monoxide (CO)) and additional testing (VOC and benzene).

The new standard permit would require that the emissions from some process units now be controlled. This would typically be accomplished with a flare. The capital cost for installation of a flare will be about \$10,000 to \$20,000 for a typical OGS with operating costs mainly due to the cost of addition of natural gas

fuel. Larger sites may require larger flares, but these are generally installed currently. Additionally, monitoring/sampling ports would be required on flares at a cost of about \$2,000.

Continuous monitoring of flare stream composition to determine heat content or direct monitoring of heat content using a calorimeter and continuous monitoring of actual exit velocity are options under this proposed rule. A stream composition analyzer for a flare will cost about \$80,000 to \$100,000. Operation of a composition analyzer will cost about \$20,000 to \$30,000 per year. A calorimeter analyzer for a flare will cost about \$24,000 to \$40,000. Operation of a calorimeter analyzer will cost about \$5,000 per year. This cost does not include a sampling condition system if needed which would cost about \$16,000. A continuous flow analyzer for a flare would be required if either the composition analyzer or calorimeter is used and will cost about \$80,000 to \$100,000. Operation of a flow analyzer will cost about \$5,000 per year.

The new standard permit would require continuous measurement of condenser outlet gas temperature. A temperature measuring device (thermocouple) monitor will not significantly increase cost. A continuous temperature monitor would cost about \$4,000. Operation of a continuous temperature monitor will cost up to about \$200 per year.

The new standard permit would have emission limits for NO<sub>x</sub> and CO for boilers, reboilers, heater-treaters, and process heaters, less than 40 million British thermal units per hour (MMBtu/hr) firing rate. The emission limits are already commonly achieved and will not be expected to increase costs.

The new standard permit would have emission limits for NO<sub>x</sub> and CO for boilers, reboilers, heater-treaters, and process heaters, equal to or greater than 40 MMBtu/hr firing rate. Boilers, reboilers, heater-treaters, and process heaters, equal to or greater than 40 MMBtu/hr firing rate will not be expected at a typical OGS. Additionally, the emissions limits are currently required in the Air Quality Standard Permit for Boilers.

The new standard permit would require additional records requirements. The TCEQ would not be able to assess additional costs, if any, due to additional records requirements, as some companies already maintain such records, some of the records are already required by other government agencies (such as the Texas Railroad Commission), and some of the records are needed for acceptable business practices.

Under the requirements of this new standard permit compressor engines may require an upgrade to their emissions control catalyst system at a cost of about \$6.00 per horse power. Installation of a full catalyst system would cost about \$28 per horse power. The resulting total cost, based on engines typically found at an OGS is \$50,000 to \$100,000 per engine.

Engines will have to do a quarterly photo ionization detector test which is about \$1,000 per test, due to the SIP engines in Dallas/Fort Worth already required to do this test since 2007.

The new standard permit would require that process and storage tanks be painted in a reflective color. Typical costs per site would be about \$6,000 for surface preparation and painting and \$20,000 if containment of emissions is needed. This cost could increase to \$52,000 if the removed existing paint contains lead and containment or special disposal is required.

#### SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

Adverse fiscal implications may be anticipated for some small or micro-businesses operating oil and gas production and transportation sites upon implementation of the proposed PBR or non-rule standard permit. Small and micro-businesses would be subject to the same requirements as other businesses and would only be affected by the proposed rule if facilities are modified or new facilities are constructed. There are an estimated 500,000 OGS that may be affected by the proposed rules. It is further estimated that 27%, or 135,000 of these sites, may qualify as small businesses. The new PBR or non-rule standard permit will require the monitoring of fugitive emissions, the sampling of gas streams, and other controls and procedures. Modified or new oil and gas transportation and production sites will incur permitting and operational costs to obtain a new PBR or non-rule standard permit. A facility that increases its emissions by 5 tons per year in VOCs or more than 0.1 tons per year in sulfur compounds would be subject to the new authorization requirements. The same potential costs and fiscal implications identified in the PUBLIC BENEFITS SECTION of this fiscal note for businesses would apply to small and micro-businesses affected by the proposed rulemaking.

#### SMALL BUSINESS REGULATORY FLEXIBILITY ANALYSIS

The commission has reviewed this proposed rulemaking and determined that a small business regulatory flexibility analysis is not required because the proposed rule is necessary to ensure that emissions from affected facilities are protective of human health and the environment. The commission has determined that alternatives available to minimize any adverse impacts to small businesses would not be as protective of the health, safety, or environmental welfare of the state.

#### LOCAL EMPLOYMENT IMPACT STATEMENT

The commission has reviewed this proposed rulemaking and determined that a local employment impact statement is not required because the proposed rule does not adversely affect a local economy in a material way for the first five years that the proposed rule is in effect.

#### DRAFT REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the proposed rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225 and determined that the proposed rule does not meet the definition of a "major environmental rule." Texas Government Code, §2001.0225 states that a "major environmental rule" is, "a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state." While the purpose of this rulemaking is to increase protection of the environment and reduce risk to human health, it is not expected that this rulemaking will adversely affect in a material way the economy, a sector of the economy, productivity, jobs, the environment, or the public health and safety of the state or a sector of the state.

Furthermore, while the proposed rulemaking does not constitute a major environmental rule, even if it did, a regulatory impact analysis would not be required because the proposed rulemaking does not meet any of the four applicability criteria for requiring a regulatory impact analysis for a major environmental rule.

Texas Health and Safety Code (THSC), §2001.0225 applies only to a major environmental rule which: "1) exceeds a standard set by federal law, unless the rule is specifically required by state law; 2) exceeds an express requirement of state law, unless the rule is specifically required by federal law; 3) exceeds a

requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopts a rule solely under the general powers of the agency instead of under a specific state law." The proposed rulemaking does not meet any of the four applicability criteria listed in Texas Government Code, §2001.0225 because: 1) the proposed rulemaking is designed to meet, not exceed the relevant standard set by federal law; 2) parts of the proposed rulemaking are directly required by state law; 3) no contract or delegation agreement covers the topic that is the subject of this rulemaking; and 4) the proposed rulemaking is authorized by specific sections of THSC, Chapter 382 (also known as the Texas Clean Air Act), which is cited in the STATUTORY AUTHORITY section.

The specific intent of the proposed rulemaking is to repeal the current requirements of §116.620 and implement a new set of requirements for the non-rule standard permit and PBR. The new standard permit and PBR requirements will provide an updated, comprehensive, and protective authorization for many common oil and gas facilities in Texas. The proposed standard permit and PBR will include operating specifications and emissions limitations for typical equipment (facilities) during normal operation, which includes production and planned maintenance, start-up, and shutdown. Also, consideration of current emission quantification methods, capture and recovery devices, and control equipment will be part of the revised authorizations. The proposed standard permit and PBR will specifically address the appropriateness of multiple authorizations at one site and would reference the many new federal standards which have been promulgated by the EPA, as well as include revised criteria for registration and changes at existing, authorized sites.

The commission invites public comment on the draft regulatory impact analysis determination. Written comments on the draft regulatory impact analysis determination may be submitted to the contact person at the address listed under the SUBMITTAL OF COMMENTS section of this preamble.

#### TAKINGS IMPACT ASSESSMENT

The commission completed a takings impact assessment for this rulemaking action under Texas Government Code, §2007.043. The primary purpose of the rulemaking is to repeal §116.620 in order to replace it with a new non-rule standard permit for the construction and modification of oil and gas facilities. The repeal of this standard permit and the concurrent repeal of the PBR and the issuance of the new standard permit and PBR do not affect private property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of a governmental action. This rulemaking will not revoke the authorizations of those facilities that are authorized under the previous §106.352. The new PBR requirements would only apply to new or modified facilities. Consequently, this rulemaking action does not meet the definition of a takings under Texas Government Code, §2007.002(5).

#### CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission reviewed the proposed rulemaking and found the proposal is a rulemaking identified in the Coastal Coordination Act Implementation Rules, 31 TAC §505.11(b)(2), relating to rules subject to the Coastal Management Program (CMP), and will, therefore, require that goals and policies of the CMP be considered during the rulemaking process. The commission reviewed this proposed rulemaking for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council and determined that the proposed repeal is consistent with CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the

diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)).

No new sources of air contaminants will be authorized and the revisions will maintain the same level of emissions control as previous rules. The CMP policy applicable to this rulemaking action is the policy that the commission's rules comply with federal regulations in 40 Code of Federal Regulations, to protect and enhance air quality in the coastal areas (31 TAC §501.32). This rulemaking action complies with 40 Code of Federal Regulations Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans. Therefore, in accordance with 31 TAC §505.22(e), the commission affirms that this rulemaking action is consistent with CMP goals and policies.

Written comments on the consistency of this rulemaking may be submitted to the contact person at the address listed under the SUBMITTAL OF COMMENTS section of this preamble.

#### ANNOUNCEMENT OF HEARING

The commission will hold a public hearing on this proposal in Austin on September 14, 2010 at 10:00 a.m. in Building E, Room 201S, at the commission's central office located at 12100 Park 35 Circle. The hearing is structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. Open discussion will not be permitted during the hearing; however, commission staff members will be available to discuss the proposal 30 minutes prior to the hearing.

Persons who have special communication or other accommodation needs who are planning to attend the hearing should contact Charlotte Horn, Office of Legal Services at (512) 239-0779. Requests should be made as far in advance as possible.

#### SUBMITTAL OF COMMENTS

Written comments may be submitted to Michael Parrish, MC 205, Office of Legal Services, Texas

Commission on Environmental Quality, P.O. Box 13087, Austin, Texas 78711-3087, or faxed to (512)

239-4808. Electronic comments may be submitted at: <http://www5.tceq.state.tx.us/rules/ecomments/>. File size restrictions may apply to comments being submitted via the eComments system. All comments should reference Rule Project Number 2010-018-106-PR. The comment period closes on September 17, 2010.

Copies of the proposed rulemaking can be obtained from the commission's Web site at

[http://www.tceq.state.tx.us/nav/rules/propose\\_adopt.html](http://www.tceq.state.tx.us/nav/rules/propose_adopt.html). For further information, please contact Beecher Cameron, Air Permits Division at 512-239-1495.

**SUBCHAPTER F: STANDARD PERMITS**

**[\§116.620]**

STATUTORY AUTHORITY

This repeal is proposed under Texas Health and Safety Code (THSC), §382.011, General Powers and Duties, which authorizes the commission to control the quality of the state's air; THSC §382.023, Orders, which authorizes the commission to issue orders necessary to carry out the policy and purposes of the Texas Clean Air Act (TCAA), THSC, §382.051, Permitting Authority of Commission; Rules, which authorizes the commission to issue permits, including THSC, §382.057 permits by rule for insignificant facilities; THSC, §382.05195, Standard Permit, which authorizes the commission to issue a permit for new or existing similar facilities; and THSC, §382.0513, Permit Conditions, which authorizes the commission to establish and enforce permit conditions consistent with TCAA, Subchapter C.

The proposed repeal implements THSC, §§382.011, 382.023, 382.051, 382.057, 382.05195, and 382.0513.

**[\§116.620. Installation and/or Modification of Oil and Gas Facilities.]**

[(a) Emission specifications.]

[(1) Venting or flaring more than 0.3 long tons per day of total sulfur shall not be allowed.]

[(2) No facility shall be allowed to emit total uncontrolled emissions of sulfur compounds, except sulfur dioxide (SO<sub>2</sub>), from all vents (excluding process fugitives emissions) equal to or greater than four pounds per hour unless the vapors are collected and routed to a flare.]

[(3) Any vent, excluding any safety relief valves that discharge to the atmosphere only as a result of fire or failure of utilities, emitting sulfur compounds other than SO<sub>2</sub> shall be at least 20 feet above ground level.]

[(4) New or modified internal combustion reciprocating engines or gas turbines permitted under this standard permit shall satisfy all of the requirements of §106.512 of this title (relating to Stationary Engines and Turbines), except that registration using the Form PI-7 or PI-8 shall not be required. Emissions from engines or turbines shall be limited to the amounts found in §106.4(a)(1) of this title (relating to Requirements for Permitting by Rule).]

[(5) Total Volatile Organic Compound (VOC) emissions from a natural gas glycol dehydration unit shall not exceed ten tons per year (tpy) unless the vapors are collected and controlled in accordance with subsection (b)(2) of this section.]

[(6) Any combustion unit (excluding flares, internal combustion engines, or natural gas turbines), with a design maximum heat input greater than 40 million British thermal units (Btu) per hour (using lower heating values) shall not emit more than 0.06 pounds of nitrogen oxides per million Btu.]

[(7) No facility which is less than 500 feet from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than ten tpy, but less than 25 tpy, unless the equipment is inspected and repaired according to subsection (c)(1) of this section.]

[(8) No facility which is 500 feet or more from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 25 tpy unless the equipment is inspected and repaired according to subsection (c)(1) of this section.]

[(9) No facility which is less than 500 feet from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 25 tpy unless the equipment is inspected and repaired according to subsection (c)(2) of this section.]

[(10) No facility shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 40 tpy unless the equipment is inspected and repaired according to subsection (c)(2) of this section.]

[(11) No facility which is located less than 1/4 mile from the nearest off-plant receptor shall be allowed to emit hydrogen sulfide H<sub>2</sub>S or SO<sub>2</sub> process fugitive emissions unless the equipment is inspected and repaired according to subsection (c)(3) of this section. No facility which is located at least 1/4 mile from the nearest off-plant receptor shall be allowed to emit H<sub>2</sub>S or SO<sub>2</sub> process fugitive emissions unless the equipment is inspected and repaired according to subsection (c)(3) of this section or unless the H<sub>2</sub>S or SO<sub>2</sub> emissions are monitored with ambient property line monitors according to

subsection (e)(1) of this section. Components in sweet crude oil or gas service as defined by Chapter 101 of this title (relating to General Air Quality Rules) are exempt from these limitations.]

[(12) Flares shall be designed and operated in accordance with 40 Code of Federal Regulations (CFR), Part 60.18 or equivalent standard approved by the commission, including specifications of minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring. If necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes. An automatic ignition system may be used in lieu of a continuous pilot.]

[(13) Appropriate documentation shall be submitted to demonstrate that compliance with the Prevention of Significant Deterioration (PSD) and nonattainment new source review provisions of the FCAA, Parts C and D, and regulations promulgated thereunder, and with Subchapter C of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)) are being met. The oil and gas facility shall be required to meet the requirements of Subchapter B of this chapter (relating to New Source Review Permits) instead of this subchapter if a PSD or nonattainment permit or a review under Subchapter C of this chapter is required.]

[(14) Documentation shall be submitted to demonstrate compliance with applicable New Source Performance Standards (NSPS, 40 CFR Part 60).]

[(15) Documentation shall be submitted to demonstrate compliance with applicable National Emission Standards for Hazardous Air Pollution (NESHAP, 40 CFR Part 61).]

[(16) Documentation shall be submitted to demonstrate compliance with applicable maximum achievable control technology standards as listed under 40 CFR Part 63, promulgated by the EPA under FCAA, §112 or as listed in Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA §112, 40 CFR Part 63)).]

[(17) New and increased emissions shall not cause or contribute to a violation of any National Ambient Air Quality Standard or regulation property line standards as specified in Chapters 111, 112, and 113 of this title (relating to Control of Air Pollution from Visible Emissions and Particulate Matter; Control of Air Pollution from Sulfur Compounds; and Control of Air Pollution from Toxic Materials). Engineering judgment and/or computerized air dispersion modeling may be used in this demonstration. To show compliance with §116.610(a)(1) of this title (relating to Applicability) for H<sub>2</sub>S emissions from process vents, ten milligrams per cubic meter shall be used as the "L" value instead of the value represented by §116.610(a)(1) of this title.]

[(18) Fuel for all combustion units and flare pilots shall be sweet natural gas or liquid petroleum gas, fuel gas containing no more than ten grains of total sulfur per 100 dry standard cubic feet (dscf), or field gas. If field gas contains more than 1.5 grains of H<sub>2</sub>S or 30 grains total sulfur compounds per 100 dscf, the operator shall maintain records, including at least quarterly measurements of fuel H<sub>2</sub>S and total sulfur content, which demonstrate that the annual SO<sub>2</sub> emissions from the facility do not exceed the limitations listed in the standard permit registration. If a flare is the only combustion unit on a property, the operator shall not be required to maintain such records on flare pilot gas.]

[(b) Control requirements.]

[(1) Floating roofs or equivalent controls shall be required on all new or modified storage tanks, other than pressurized tanks which meet §106.476 of this title (relating to Pressurized Tanks or Tanks Vented to Control), unless the tank is less than 25,000 gallons in nominal size or the vapor pressure of the compound to be stored in the tank is less than 0.5 pounds per square inch absolute (psia) at maximum short-term storage temperature.]

[(A) For internal floating roofs, mechanical shoe primary seal or liquid-mounted primary seal or a vapor-mounted primary with rim-mounted secondary seal shall be used.]

[(B) Mechanical shoe or liquid-mounted primary seals shall include a rim-mounted secondary seal on all external floating roofs tanks. Vapor-mounted primary seals will not be accepted.]

[(C) All floating roof tanks shall comply with the requirements under §115.112(a)(2)(A) - (F) of this title (relating to Control Requirements).]

[(D) In lieu of a floating roof, tank emissions may be routed to: ]

[(i) a destruction device such that a minimum VOC destruction efficiency of 98% is achieved; or]

[(ii) a vapor recovery system such that a minimum VOC recovery efficiency of 95% is achieved.]

[(E) Independent of the permits by rule listed in this paragraph, if the emissions from any fixed roof tank exceed ten tpy of VOC or ten tpy of sulfur compounds, the tank emissions shall be routed to a destruction device, vapor recovery unit, or equivalent method of control that meets the requirements listed in subparagraph (D) of this paragraph.]

[(2) The VOC emissions from a natural gas glycol dehydration unit shall be controlled as follows.]

[(A) If total uncontrolled VOC emissions are equal to or greater than ten tpy, but less than 50 tpy, a minimum of 80% by weight minimum control efficiency shall be achieved by either operating a condenser and a separator (or flash tank), vapor recovery unit, destruction device, or equivalent control device.]

[(B) If total uncontrolled VOC emissions are equal to or greater than 50 tpy, a minimum of:]

[(i) 98% by weight minimum destruction efficiency shall be achieved by a destruction device or equivalent; or]

[(ii) 95% by weight minimum control efficiency shall be achieved by a vapor recovery system or equivalent.]

[(c) Inspection requirements.]

[(1) Owners or operators who are subject to subsection (a)(7) or (8) of this section shall comply with the following requirements.]

[(A) No component shall be allowed to have a VOC leak for more than 15 days after the leak is detected to exceed a VOC concentration greater than 10,000 parts per million by volume (ppmv) above background as methane, propane, or hexane, or the dripping or exuding of process fluid based on sight, smell, or sound for all components. The VOC fugitive emission components which contact process fluids where the VOCs have an aggregate partial pressure or vapor pressure of less than 0.5 psia at 100 degrees Fahrenheit are exempt from this requirement. If VOC fugitive emission components are in service where the operating pressure is at least 0.725 pounds per square inch (psi) (five kilopascals (Kpa)) below ambient pressure, then these components are also exempt from this requirement as long as the equipment is identified in a list that is made available upon request by the agency representatives, the EPA, or any other air pollution agency having jurisdiction. All piping and valves two inches nominal size and smaller, unless subject to federal NSPS requiring a fugitive VOC emissions leak detection and repair program or Chapter 115 of this title (relating to Control of Air Pollution from Volatile Organic Compounds), are also exempt from this requirement.]

[(B) All technically feasible repairs shall be made to repair a VOC leaking process fugitive component within 15 days after the leak is detected. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. The executive director, at his discretion, may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown.]

[(C) New and reworked underground process pipelines containing VOCs shall contain no buried valves such that process fugitive emission inspection and repair is rendered impractical.]

[(D) To the extent that good engineering practice will permit, new and reworked valves and piping connections in VOC service shall be so located to be reasonably accessible for leak-checking during plant operation. Valves elevated more than two meters above a support surface will be considered non-accessible and shall be identified in a list to be made available upon request.]

[(E) New and reworked piping connections in VOC service shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Flanges in VOC service shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.]

[(F) Each open-ended valve or line in VOC service, other than a valve or line used for safety relief, shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.]

[(G) Accessible valves in VOC service shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. For valves equipped with rupture discs, a pressure gauge shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity, but no later than the next process shutdown. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc or venting to a control device are exempt from monitoring.]

[(H) Dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system, submerged pumps, or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic driven pumps) are exempt from monitoring.]

[(I) All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.]

[(J) After completion of the required quarterly inspections for a period of at least two years, the operator of the oil and gas facility may request in writing to the Office of Permitting, Remediation, and Registration that the monitoring schedule be revised based on the percent of valves leaking. The percent of valves leaking shall be determined by dividing the sum of valves leaking during

current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements. This request shall include all data that has been developed to justify the following modifications in the monitoring schedule.]

[i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.]

[ii) After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.]

[(2) Owners or operators who are subject to subsection (a)(9) or (10) of this section shall comply with the following requirements.]

[(A) No component shall be allowed to have a VOC leak for more than 15 days after the leak is found which exceeds a VOC concentration greater than 500 ppmv for all components except pumps and compressors and greater than 2,000 ppmv for pumps and compressors above background as methane, propane, or hexane, or the dripping or exuding of process fluid based on sight, smell, or sound. The VOC fugitive emission components which contact process fluids where the VOCs have an aggregate partial pressure or vapor pressure of less than 0.044 psia at 100 degrees Fahrenheit are exempt from this requirement. If VOC fugitive emission components are in service where the operating pressure is at least 0.725 psi (five Kpa) below ambient pressure, these components are also exempt from

this requirement as long as the equipment is identified in a list that is made available upon request by agency representatives, the EPA, or any air pollution control agency having jurisdiction. All piping and valves two inches nominal size and smaller are also exempt from this requirement.]

[(B) All technically feasible repairs shall be made to repair a VOC leaking process fugitive component within 15 days after the leak is detected. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. The executive director, at his or her discretion, may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown.]

[(C) New and reworked underground process pipelines containing VOCs shall contain no buried valves such that process fugitive emission inspection and repair is rendered impractical.]

[(D) To the extent that good engineering practice will permit, new and reworked valves and piping connections in VOC service shall be so located to be reasonably accessible for leak-checking during plant operation. Valves elevated more than two meters above a support surface will be considered non-accessible and shall be identified in a list to be made available upon request.]

[(E) New and reworked piping connections in VOC service shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and

adjustments made as necessary to obtain leak-free performance. Flanges in VOC service shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.]

[(F) Each open-ended valve or line in VOC service, other than a valve or line used for safety relief, shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.]

[(G) Accessible valves in VOC service shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. For valves equipped with rupture discs, a pressure gauge shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity, but no later than the next process shutdown. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc or venting to a control device are exempt from monitoring.]

[(H) Dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order or seals equipped with an automatic seal failure detection and alarm system, submerged pumps, or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic driven pumps) are exempt from monitoring.]

[(I) All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.]

[(J) After completion of the required quarterly inspections for a period of at least two years, the operator of the oil and gas facility may request in writing to the Office of Permitting, Remediation, and Registration that the monitoring schedule be revised based on the percent of valves leaking. The percent of valves leaking shall be determined by dividing the sum of valves leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements. This request shall include all data that has been developed to justify the following modifications in the monitoring schedule.]

[(i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.]

[(ii) After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.]

[(K) A directed maintenance program shall be used and consist of the repair and maintenance of VOC fugitive emission components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be remonitored within 30 days of being placed back into VOC service.]

[(3) For owners and operators who are subject to the applicable parts of subsection (a)(11) of this section, auditory and visual checks for SO<sub>2</sub> and H<sub>2</sub>S leaks within the operating area shall be made every day. Immediately, but no later than eight hours upon detection of a leak, operating personnel shall take the following actions:]

[(A) isolate the leak; and]

[(B) commence repair or replacement of the leaking component; or]

[(C) use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.]

[(d) Approved test methods.]

[(1) An approved gas analyzer used for the VOC fugitive inspection and repair requirement in subsection (c) of this section, shall conform to requirements listed in 40 CFR §60.485(a) and (b).]

[(2) Tutweiler analysis or equivalent shall be used to determine the H<sub>2</sub>S content as required under subsections (a) and (e) of this section.]

[(3) Proper operation of any condenser used as a VOC emissions control device to comply with subsection (a)(5) of this section shall be tested to demonstrate compliance with the minimum control

efficiency. Sampling shall occur within 60 days after start-up of new or modified facilities. The permittee shall contact the Engineering Services Section, Office of Compliance and Enforcement 45 days prior to sampling for approval of sampling protocol. The appropriate regional office in the region where the source is located shall also be contacted 45 days prior to sampling to provide them the opportunity to view the sampling. Neither the regional office nor the Engineering Services Section, Office of Compliance and Enforcement personnel are required to view the testing. Sampling reports which comply with the provisions of the "TNRCC Sampling Procedures Manual," Chapter 14 ("Contents of Sampling Reports," dated January 1983 and revised July 1985), shall be distributed to the appropriate regional office, any local programs, and the Engineering Services Section, Office of Compliance and Enforcement.]

[ (e) Monitoring and recordkeeping requirements.]

[ (1) If the operator elects to install and maintain ambient H<sub>2</sub>S property line monitors to comply with subsection (a)(11) of this section, the monitors shall be approved by the Engineering Services Section, Office of Compliance and Enforcement office in Austin, and shall be capable of detecting and alarming at H<sub>2</sub>S concentrations of ten ppmv. Operations personnel shall perform an initial on-site inspection of the facility within 24 hours of initial alarm and take corrective actions as listed in subsection (c)(3)(A) - (C) of this section within eight hours of detection of a leak.]

[ (2) The results of the VOC leak detection and repair requirements shall be made available to the executive director or any air pollution control agency having jurisdiction upon request. Records, for all components, shall include:]

[(A) appropriate dates;]

[(B) test methods;]

[(C) instrument readings;]

[(D) repair results; and]

[(E) corrective actions. Records of flange inspections are not required unless a leak is detected.]

[(3) Records for repairs and replacements made due to inspections of H<sub>2</sub>S and SO<sub>2</sub> components shall be maintained.]

[(4) Records shall be kept for each production, processing, and pipeline tank battery or for each storage tank if not located at a tank battery, on a monthly basis, as follows:]

[(A) tank battery identification or storage tank identification, if not located at a tank battery;]

[(B) compound stored;]

[(C) monthly throughput in barrels/month; and]

[(D) cumulative annual throughput, barrels/year.]

[(5) A plan shall be submitted to show how ongoing compliance will be demonstrated for the efficiency requirements listed in subsection (b)(1)(D) of this section. The demonstration may include, but is not limited to, monitoring flowrates, temperatures, or other operating parameters.]

[(6) Records shall be kept on at least a monthly basis of all production facility flow rates (in standard cubic feet per day) and total sulfur content of process vents or flares or gas processing streams. Total sulfur shall be calculated in long tons per day.]

[(7) Records shall be kept of all ambient property line monitor alarms and shall include the date, time, duration, and cause of alarm, date and time of initial on-site inspection, and date and time of corrective actions taken.]

[(8) All required records shall be made available to representatives of the agency, the EPA, or local air pollution control agencies upon request and be kept for at least two years. All required records shall be kept at the plant site, unless the plant site is unmanned during business hours. For plant sites ordinarily unmanned during business hours, the records shall be maintained at the nearest office in the state having day-to-day operations control of the plant site.]