I. EXECUTIVE SUMMARY

The Texas Commission on Environmental Quality (TCEQ or commission) is in the process of evaluating all permits by rule (PBR) in Title 30, Texas Administrative Code (30 TAC) Chapter 106, Permits by Rule, and standardized authorizations through a multiple-phased process known as the PBR Study. The goals of the study include: update administrative and technical requirements; make appropriate changes to registration or notification requirements; ensure that air emissions from specific facilities are protective of human health and welfare; include practically enforceable record requirements; authorize planned maintenance, startup and shutdown (MSS) activities and allow the executive director to more effectively focus resources on facilities that significantly contribute air contaminants to the atmosphere. Through this study, the executive director has discovered the need to significantly revise the PBR and standard permit for oil and gas facilities or groups of facilities at oil and gas sites (OGS). In addition, recent monitoring data indicates updated regulatory oversight would be beneficial to ensure protectiveness for air contaminants such as benzene, hydrogen sulfide (H₂S), and other air contaminants associated with oil and gas production sites. These updates are particularly critical for OGS in urban locations or in close proximity to the public. Overall, this rulemaking is necessary to ensure that the authorizations are improved for enforceability, updated based on current scientific information, and to properly regulate all operations located at an oil and gas site.

As a result, the TCEQ is proposing to repeal 30 TAC §106.352, Oil and Gas Production Facilities, and readopt it with new requirements, and repeal 30 TAC §116.620, Installation and/or Modification of Oil and Gas Facilities and replace it with this new air quality standard permit. The commission proposes repeal of the existing standard permit in 30 TAC §116.620, Installation and/or Modification of Oil and Gas Facilities, as well as the repeal and new §106.352, in a separate action. The change will prevent conflicting authorization methods for the same types of facilities and not allow new authorizations to be considered once the new proposed standard permit is effective. These authorizations will regulate all new OGS, new facilities at existing OGS, or changes at existing facilities and sites.

II. HIERARCHY OF AIR AUTHORIZATIONS

Texas Health and Safety Code (THSC) §382.0518 establishes regulations for all facilities which may have the potential to emit air contaminants to obtain an air authorization and meet appropriate emission limits and control requirements. To ensure that the administrative and technical requirements for facilities are appropriate to their potential emissions releases, the commission has established a hierarchy of authorization mechanisms.

The most negligible sources are covered under de minimis in 30 TAC §116.119, Deminimus Facilities or Sources, and by definition, do not have substantial limitations or requirements. Facilities which are not de minimis, but instead are insignificant, can be authorized by a PBR under 30 TAC Chapter 106. The PBRs are rules with general and specific requirements promulgated by the commission. PBRs are usually specific to an industry or activity. A facility authorized by PBR must meet each condition of the rule exactly, with no exceptions. The next category of authorizations is a standard permit, (30 TAC 116, Subchapter F), which are more complex than PBRs, but do not require case-by-case reviews or trigger federal pre-construction authorization. The standard permits are also usually specific to an industry or defined activity at a site. A facility or group of facilities authorized by standard permit must meet each condition of the permit exactly, with no exceptions. The next category of available authorizations is case-by-case state New Source Review (NSR) permits. Specific permit conditions and limitations are reviewed...
and negotiated during these permit reviews for sources which are not de minimis, insignificant, or cannot meet PBR or standard permit requirements. For the largest sources, federal preconstruction permit reviews are required.

III. EXPLANATION AND BACKGROUND OF AIR QUALITY STANDARD PERMIT

Currently, an OGS may be authorized by PBR, standard permit, case-by-case NSR permit, or a combination of these authorizations. This proposed standard permit, and the corresponding PBR, are being developed to provide an updated, comprehensive, and protective authorization for many common OGS and facilities in Texas. The proposed standard permit will include specifications and limitations for typical equipment (facilities) during normal operation, including production as well as planned maintenance, startup, and shutdown (MSS). The proposed PBR and standard permit have been developed considering current emission capture and control equipment.

There have also been historical concerns regarding the use of multiple authorizations for related and unrelated facility operations at the same site or location. The proposed standard permit and PBR address the appropriateness of multiple authorizations at one contiguous property. This proposal also includes revised criteria for registration and changes at existing, authorized sites.

One of the continuing limitations for the proposed standard permit would limit the authorizations to OGS which do not require federal preconstruction authorization under Title 40 Code of Federal Regulations (40 CFR) Part 51 (Prevention of Significant Deterioration (PSD)) or 40 CFR Part 52 (Nonattainment New Source Review (NNSR)). New and existing OGS may be subject to the Title V federal operating permit program as well and must obtain a Site Operating Permit (SOP) or a General Operating Permit (GOP).

Based on recent regulatory changes required by EPA and 40 CFR Part 70, a GOP can only be used by sites authorized under PBR or standard permit. If a major site subject to Title V does not qualify for a PBR or standard permit, it must obtain a SOP (submittal deadline was December 2008).

A primary goal of the PBR Study is to verify that all general authorizations of the commission, such as PBRs and standard permits, are protective of human health and welfare and recommend rule changes to ensure or improve their continued protectiveness. To achieve this goal, an impacts evaluation was conducted to verify that individual PBR or standard permit claims will not adversely impact human health and welfare, that is, be “protective.”

For each type or group of typical OGS facilities and activities, the executive director staff analyzed the following questions: what is the facility; how does it operate; what is its function; what was the basis for the information used; how are emissions from production operations generated, estimated and released; what is the expected type and quantity of emissions from production; what are the appropriate capture or control systems for production operations; what are the appropriate best management practices (BMP) and/or best available control technology (BACT) for this facility; what are the emission dispersion characteristics for production; and are the impacts of the emissions protective of public health and welfare. In addition, for related operations and activities at OGS, the commission reviewed the following: what is planned MSS; how are emissions from planned MSS activities generated, estimated and released; what is the expected type and quantity of emissions from MSS; what are the appropriate capture or control systems for MSS activities; what is the appropriate BACT for this MSS activity; what are the emission dispersion characteristics for MSS emissions; and are the impacts of the emissions protective of public health and welfare.

In 2006, the commission distributed a preliminary proposal for the OGS, which included updates based on science and emissions information available at the time. This package was discussed at numerous
stakeholders meetings and evaluated by state and federal regulatory staff. At the time, it was determined that additional, detailed, information was needed to ensure a more comprehensive and representative review of facilities, controls, and emissions associated with OGS. Research in many areas has continued for several years, and the results of those efforts are included in this standard permit. In addition, numerous comments were received from the regulated community, mainly expressing concerns over more detailed and prescriptive emission limits, sampling and monitoring requirements, preconstruction registrations, and control specifications.

Any OGS under a standard permit may only consist of the facilities and operations evaluated by the commission. The executive director staff has evaluated the following facilities historically referred to as “oil and gas production facilities” claimed under §106.352, as well as numerous other PBRs, including: fixed-roof, internal floating roof, external floating roof and pressurized tanks storing or transferring crude oil, natural gas, condensate, liquid petroleum gas, fuel oil, diesel fuel, gasoline, amine treatment chemicals, glycol treatment chemicals, methanol, speciated liquids and gases, produced and salt water, and slop/sump oil; liquid and gas truck loading and pipeline transfer facilities; separators (free-water knockouts, gunbarrels, oil/water separators, membrane units); condensers; treatment units (heat exchangers, refrigeration units, glycol dehydration units, amine units and other sweetening units, heater treaters, methanol injection, molecular/mole sieves, absorbers, or adsorbers); natural gas liquid recovery units (cryogenic expansion, refrigeration, absorption, adsorption processes); compressors, pumps, and meters; fugitive components (valves, pipe flanges and connectors, pump and compressor seals, and process drains); cooling towers and in-direct heat exchangers; combustion units (boilers, reboilers, heaters, heater treaters, reciprocating engines and turbines, flares, thermal destruction devices); and other facilities meeting the conditions of certain permits by rule in 30 TAC Chapter 106 including: §106.181, Used Oil Combustion Units; Boilers; §106.183, Heaters and Other Combustion Devices; §106.261; Facilities (Emission Limitations); §106.262, Facilities (Emissions and Distance Limitations); §106.264, Replacements of Facilities; §106.351, Salt Water Disposal (Petroleum); §106.352, Oil and Gas Production Facilities; §106.353, Temporary Oil and Gas Facilities; §106.371, Storage and Handling of Dry Natural Gas; §106.472, Organic and Inorganic Liquid Loading and Unloading; §106.473, Organic Liquid Loading and Unloading; §106.475, Pressurized Tanks or Tanks Vented to a Firebox; §106.476, Pressurized Tanks or Tanks Vented to Control; §106.478, Storage Tank and Change of Service; §106.492, Flares; §106.511, Portable and Emergency Engines and Turbines; and §106.512, Stationary Engines and Turbines.

Additional information was requested from stakeholders or researched by the executive director staff since the previous rules proposal review. Where sufficient information was available, emissions, potential impacts, best management practices (BMP), MSS, and best available control technology (BACT) were considered and used to develop this proposal for all identifiable facilities, operations and activities. For production operations, the following facilities were reviewed: separators, amine treaters, iron sponge units, glycol reboilers and treaters, cooling towers, cryogenic units and other natural gas liquid recovery units, deethanizers, heat exchangers, engines and turbines, storage tanks and material handling (flash, working, breathing losses for crude oil, condensate, produced water, and natural gas). Truck loading, fuel tanks, and slop/sump oil tanks. This review also encompassed all types of treatments and chemicals, including: corrosion inhibitors, surfactants, scale inhibitors, methanol injection, glycols, amines, and other regenerative or non regenerative sweetening systems with solid or liquid treatment chemicals. Particular focus was made for recovery and controls, including vapor recovery units (VRU), flares, thermal oxidizers, vapor combustors, and engine catalysts. For planned MSS, certain facilities requiring periodic inspection, cleaning and maintenance included storage tanks, pressurized and non-pressurized process vessels, and associated piping and fugitive components. These activities primarily consist of purging/degasassing, opening (interior wetted surface area), cleaning, and refilling/recharging, and returning to service a variety of systems, including: separators, treatment chemicals, methanol injection, glycol dehydrators, molecular sieves, iron sponge, amine treaters, SulfaTreat, regenerative or non regenerative sweetening systems with
solid or liquid treatment chemicals, cooling towers, cryogenic units, deethanizers, glycol regenerators, absorbers, adsorbers, heat exchangers, boilers, reboilers, heaters, heater treaters, crude oil tanks, condensate tanks, produced water tanks, loading racks, and slop/sump oil tanks. Various capture and control equipment and emission release options was also reviewed, including: alternative operations or diverted stream when control systems are out of service for planned maintenance; additional streams when purging/degassing equipment; flares, thermal oxidizers, vapor combustors; and VRUs. Finally, the commission reviewed temporary maintenance facilities, including abrasive blasting, surface preparation and coating, testing of an engine or turbine, temporary piping and associated facilities to bypass equipment.

IV. FACILITIES, EMISSIONS, AND CONTROLS

The oil and gas production and transportation industry consists of a great variety of handling and processing facilities, emissions, and control devices. The executive director staff has reviewed hundreds of PBR, standard permit, and permit files to identify the most common OGS facilities which are similar in terms of operations and processes, resulting in similar potential emissions and corresponding predicted impacts. Most OGS will process gases and liquids associated with the production, conditioning, processing, and pipeline transfer of OGS fluids and gases using a variety of process equipment. These sites use various types of equipment in different ways and arranged in an almost infinite number of possible configurations. Depending on the region in Texas, the composition of the fluids and gases at a given site also varies greatly. It was necessary for the commission to evaluate each type of equipment that is typically found at existing OGS. The facilities and operations reviewed by the commission are the foundation of the proposed standard permit, and proposed authorizations will be limited to only those facilities, operations, emissions, and controls evaluated. If additional facilities or operations occur commonly at OGS throughout the state, the commission requests detailed information to broaden this evaluation. In some cases, the commission has determined that information is available, but that considerable personnel and resources are needed to establish the facts or the additional required information for consideration may not be readily available or contained in the permit files maintained by the agency. Because information is not available the commission is not including these facilities or activities in any proposed new authorization mechanisms.

It should also be noted that, at a minimum, the standard permit analysis is required by statute to include BACT. BACT is defined as technology which is technically feasible and economically reasonable. The requirements for BACT determinations consist of three tiers of review. Tier I BACT is those controls or techniques that are commonly used, many have been required in permits for an extended period of time, or have been required in recently issued permits. Tier 2 BACT is those controls or techniques which have been commonly used or required in similar industries or at sites with similar process streams. Tier 2 BACT reviews include those controls and techniques that have been determined by a regulatory agency to be technically feasible based on good engineering judgment, but may not have been used or required under Tier 1. Tier 3 BACT consists of reviews for economic reasonableness of certain controls or techniques and provide the opportunity for the regulated entity to justify that a control that is otherwise required under Tier 1 or 2 is not economically reasonable to install due to the unique circumstances of their processes.

The following discussions concern the most common facilities, equipment, and operations typically found at an oil and gas site.

A. Fugitive Components

The most universally common facility and associated emission releases at OGS are from fugitives. The federal new source review permitting definition of fugitives is an emission
release occurs when any air contaminant enters the atmosphere and cannot reasonably pass through a stack, chimney, vent, or other functionally equivalent opening designed to direct or control its flow. For purposes of dispersion modeling, the term fugitive is used to describe ground-level or minimal height releases at ambient conditions with little or no flow rate. For state permitting purposes, the term fugitive describes emissions from certain equipment, including valves, pipe flanges and connectors, seals, instrumentation, and the like – often are referenced as fugitive components. Normally, control of fugitive emissions involves minimizing leaks through equipment changes, monitoring, housekeeping, and maintenance practices. Fugitive emissions are usually released to the atmosphere at ambient temperature, have little or no velocity, and are often close to the ground. For example, emissions from truck loading can be treated as fugitive if a capture and control system is not used.

Air pollutants at OGS from fugitive components include volatile organic compounds (VOC) grouped by the TCEQ into one of three general categories, crude oil, condensate, or natural gas, and containing various levels of hazardous air pollutants (HAPs) such as benzene, toluene, ethyl benzene, and xylene (BTEX); as well as hydrogen sulfide (H₂S). Emissions that occur during production operations are directly related to the level of preventative measure applied. Fugitive emissions occur as a result of both production and MSS activities, although potentially in substantially different quantities. Emissions during MSS activities are directly related to the amount and type of gas or liquid which remain in the equipment or piping when a seal is broken or opened. Emissions from MSS activities were evaluated and found to be of the same character as production emissions. The fugitive emissions from the repair or replacement of connections was estimated to be similar in character and quantity as pipeline purging or plant blowdowns which are discussed later in this analysis. Based on the limited information available, the executive director staff assumed fugitive MSS activities occur uncontrolled at OGS.

Normally, control of fugitive emissions involves minimizing leaks and spills through equipment changes, monitoring, housekeeping, and maintenance practices. Maintenance of fugitive components requires purging associated piping and equipment prior to repair or replacement of valves, flanges, and seals. The executive director staff evaluated emissions and small blocked sections of pipelines which are purged prior to maintenance and repair. In all cases, Tier 1 BACT requires caps on open-ended lines resulting from repairs if open for more than 72 hours, regardless of size. In addition, current Tier 1 BACT for piping component fugitive emissions is estimated using emission factors from the October 2000 “Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives” TCEQ guidance document. The applicable Leak Detection and Repair (LDAR) program is determined according to the following:

1. If uncontrolled annual VOC fugitive emissions are estimated at less than 10 tons per year (tpy), there are no specific LDAR requirements which are universally expected. There are sites which must perform LDAR programs at less than 10 tpy, in accordance with 30 TAC §115.352, Control Requirements, the program referred to as “28RCT” applies.

2. If uncontrolled annual VOC fugitive emissions are estimated at equal to or greater than 10 tpy VOC, the 28M LDAR Program (with 10,000 parts per million by volume (ppmv) leak definition) applies.
If uncontrolled annual VOC fugitive emissions are estimated at equal to or greater than 25 tpy VOC, the 28VHP LDAR Program (with 500 ppmv leak definition) applies.

At sites with a field gas pneumatic power system for the valves, actuators, and pumps, there are VOC gas releases which are considered as working releases from the valves, actuators, or pumps gas vents which are not included in the fugitive component VOC emission factors. These emissions are in addition to the fugitive component VOC emissions. The manufacturer data sheet should be consulted for their emission factor which may have to be modified by the VOC and H₂S content of the field gas. For glycol dehydrators with field gas power pneumatic systems the GLYCalc computer program will estimate these additional emissions for some systems.

Based on investigations and monitoring by TCEQ field personnel and representations in permit reviews, on-going maintenance of fugitive components may not be diligently applied throughout the industry. In some cases, there have been reports of open-ended pipes and seriously leaking components at OGS, thus raising concerns over unaccounted emission releases. The Texas Railroad Commission has also recently issued an advisory to the industry, expressing similar concerns:
www.rrc.state.tx.us/forms/reports/notices/airemission21010.pdf.

Fugitive component emissions from production at OGS were estimated based upon extensive research of registration files and the 1997 Protectiveness Review for Standard Exemption No. 66 (predecessor to PBR §106.352). From this review, the commission estimates a representative, but conservative, number of 1,000 piping components per OGS, including a component breakdown of 700 flanges and 300 valves, with 50% of components in gas service and 50% in light liquid service (condensate). To evaluate production emissions, the VOC content was assumed to be 97% for liquid service and 40% for gas service. Production emissions from these facilities were estimated using emission factors from the October 2000 “Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives” TCEQ guidance document. This document details commonly accepted American Petroleum Institute (API) emission factors. While there have been several previous versions of the API factors for oil and gas sites, the most current and representative are those published in by the United States Environmental Protection Agency (EPA): “EPA: Protocol for Equipment Leak Emission Estimates” Nov. 1995, EPA 4531, R-95-017 API 46API 4638: “Calculation Workbook for Oil and Gas Production Equipment Fugitive Emissions,” July 1996.

Based on a random evaluation of registered PBR and standard permit sites, fugitive component VOC hourly emissions range from 0.01 pounds per hour (lb/hr) to 3 lb/hr, and annual emissions range from 0.01 tpy to 15 tpy. In addition, H₂S hourly emissions ranged from 0.01 lb/hr to 0.4 lb/hr and annually from < 0.01 tpy to 2 tpy. These findings correlate well with an earlier 1997 Protectiveness Review for Standard Exemption No. 66. These values assumed no open-ended pipes and reasonable diligence of inspection and timely repairs of leaking components. As a result, these parameters were used for the impact analysis and protectiveness review of fugitive components at OGS.
Planned MSS activities on pipelines occur when repairing or replacing fugitive components, purging of the piping, adding additional components, and refilling piping sections. Releases of emissions depend on the size of piping to be purged and the volume of gas it contains. Emissions and their releases are covered in the Compressor Blowdowns section.

B. Pumps and Meters

Pumps and pumpjacks are used to move material through piping and equipment at an OGS. Pumps may be driven by electric motor, steam, air, natural gas, hydraulics, internal combustion engine, or gas turbine. Electric, steam, and air–driven motors do not produce air contaminants. Internal combustion engines and turbines will have these products of combustion: nitrogen oxides (NOx), carbon monoxide (CO), VOC, particulate matter 10 microns or less in diameter (PM10), formaldehyde (HCHO), and sulfur dioxide (SO2). These facilities are covered in the Combustion Units section. Hydraulic motors may have seals and fugitive components with hydraulic fluid emissions. A well-maintained hydraulic system will have de minimis quantities of emissions from hydraulic components. A gas powered pump will emit low pressure gas emissions which are normally considered fugitive emissions after the higher pressure mechanical energy is used to power the pump. All pumps and motors will have associated piping and fugitive components, which emit VOC and possible H2S emissions from the material being handled (covered in the total component count under Fugitive Components section). Tier 1 BACT for facilities of this type are: sealed units, performing fugitive monitoring, preventative maintenance, and appropriate combustion unit limitations.

Emissions from MSS activities were evaluated and found to be of the same character as production emissions. The quantity of fugitive emissions from the repair or replacements of connections were estimated to be the same as purging (covered in the Blowdowns section). Maintenance of fugitive components requires purging associated piping and equipment prior to repair or replacement of valves, flanges, and seals. The executive director staff evaluated small quantities of emissions and small blocked sections of pipelines which are purged prior to maintenance and repair. The applicable BMP and LDAR programs are the same as discussed in Fugitive Components above. Emissions, impacts analysis, and protectiveness review are included with other fugitive component evaluations.

Meters are used throughout OGS and are used by stand-alone Lease Area Custody Transfer (LACT) operations and other processing sites units. Various types of flow measuring instrumentation may be employed to provide accurate information for the amount of product conveyed. Operating emissions from a LACT unit or metering station are normally fugitive in nature and result from piping flange connections, valves, isolation valves, and purging of instrument lines and Tier 1 BACT currently requires caps on open-ended lines resulting from repairs if open for more than 24 hours. Additional MSS releases occur during repair or maintenance of these components.

C. Separators

A separator is a piece of equipment that separates the production flow stream into gases and liquids. The size of the separator depends on the processing rate of gas and/or liquids in the production flow. The operating pressure of the separator depends on the pressure of the gas pipeline, the flowing pressure of the well, and the operating pressure desired. Separators are built in various designs, including vertical, horizontal, and spherical. Some separators are
two-phase separators, which separates the production flow into gas and liquid. Others are three-phase separators, which separate production flow into gas, crude oil, or condensate and water. Sometimes more than one stage of separation is used to increase crude oil or condensate recovery. There were several specific types of separators identified during the executive director staff’s evaluation: gun barrels, free-water knockouts, oil/water separators, and membrane units.

1. **Gun Barrel Separators**: Gun barrel tanks, also known as settling vessels, use gravity to separate the oil from the water. Given enough time, the water will settle at the bottom of the tank and the oil will rise to the top. There are various designs of gun barrels, but the two main types fall into horizontal or vertical designs. They usually are tall enough for gravity flow of the oil out of an outlet in the middle or lower part of the separator into the oil stock tank. The produced water is drawn off the bottom and gas off the top of the separator.

2. **Free-Water Knockout Separators**: These units are used to separate free gas and water from oil, and emulsions. The size depends on the desired retention time and volume of water to be handled. Time, gravity, mechanical, and sometimes chemical methods, are used to hasten separation in these separators. When heat is needed to separate an emulsion, significant fuel can be saved by using these separators to isolate the emulsion part of the flow instead of a heater being used on the total flow, saving heat, fuel and cost.

3. **Oil/Water Separators**: Oil/water separators can be electrical (sometimes called electrostatic coalesces or chem-electric treaters) or based on physical insolubility of oil and water. Oil/water separators are normally sealed units with small fugitive component VOC and possible H₂S emissions. Oil/water separators operating or handling low vapor pressure sump or slop oil may be open units with a small tank. The sealed separator may be pressurized. MSS emissions are dependent on the size of the unit and occur when opening the unit for repairs and/or clean out, resulting in VOC and possible H₂S emissions.

4. **Membrane Units**: Membrane units separate carbon dioxide (CO₂) from natural gas. The membrane units consist of polymers that allow hydrocarbons to pass through the membrane at different rates. The CO₂ membranes produce a high CO₂ concentration stream that may be sent to a pipeline for subsequent processing at another site, vented directly to the atmosphere, or vented indirectly through a control device to the atmosphere. CO₂ membranes produce a high CO₂ concentration stream from a stream of primarily methane and CO₂. Some membrane units may be used in conjunction with one or more amine units or similar units with a different treatment chemical to separate the carbon dioxide and natural gas as an intermediate step or stage of the purification process. The units have thin films of synthetic polymers where smaller or selective gas molecules can pass through increasing concentrations of certain compounds after the membrane. Another absorber solvent, such as an amine treatment unit and several stages of membrane units may be necessary for a production process to produce a high quality CO₂ to meet pipeline specifications. When the high pressure gas does not diffuse completely through the membrane it is recycled back to the previous stage as an input. These units have operational and MSS emissions as described in the Amine Treatment section, unless vent gas emissions are recycled to previous stages.
5. **For all Separators:** During normal production operations, most separators are sealed units with VOC or H₂S emissions through associated valves, flanges, and fittings (fugitive components) and are accounted for in the discussion above. In many locations, gas is sent to an available pipeline for further processing, handling and ultimate sale, resulting in no additional on-site emissions. In a few locations where petroleum liquids are produced and the produced gas flow is very low (or there is no pipeline available) the gas may be flared or released uncontrolled to the atmosphere. In most cases of uncontrolled releases, the VOC released (after subtracting methane and ethane) will not exceed 40% of the total release. The dimensions of a separator were characterized as 6 feet long and 2 feet in diameter and may be positioned either horizontally or vertically. Using the Ideal Gas Law, the volume to mass conversion was 481.93 cubic feet (cf)/lb-mole based upon an exit temperature of 200 °F. The uncontrolled VOC emissions were estimated as (100,000 cfd) x (0.40) x (1 day/24 hr) x (36 lb/lb-mole) x (1 lb-mole/ 481.93 cf) or 124.50 lb/hr. Tier I BACT for separators is a required control effectiveness of at least 95%, or using a pressurized unit and sending streams to another process which is appropriately controlled. When the flow off a separator is sent to a control device, the control device must meet the device requirements established for that system for effective control of emissions. The fugitive VOC and possible H₂S fugitive emissions from any separator are discussed in the Fugitive Components section.

MSS emissions for a separator should be fugitive emissions of VOC and H₂S when the separator is opened for any repair or cleaning. The magnitude of these emissions vary depending on the size of the vessel, the operating pressure, if the pressurized vessel is vented to a control before opening, the amount of material on the wetted inside surface, and the amount of liquids and gases remaining in the separator before opening. Since the separators are commonly pressurized vessels, the uncontrolled degassing activity emissions are most like the dispersion characteristics for Blowdowns, and are included in that section. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device’s higher temperature, flow rate and stack release height, along with possible sulfur compounds (H₂S converts to SO₂) and products of combustion, and the dispersion characteristics will match that of the control device.

**D. Condensers**

Condensers are used to liquefy gaseous vapors that are condensable to increase the recovery of VOC compounds and/or reduce downstream loading by removing undesirable materials such as water. These condensers are normally of the air-type, but occasionally water-type condensers are used. Condensers are normally a pipe-type device with the stream to be condensed flowing down the inside of the pipe. There are no emissions except for fugitive components as the units are otherwise sealed, which is Tier I BACT. The TCEQ normally assumes any air condenser will be designed to this standard, but may request design information on any condenser unit for verification. Efficiencies greater than 80% for an air condenser may be claimed only with specific performance data due to the potential variability of condenser designs and operations. Air condensers should be designed to achieve at least an annual 80% recovery of VOC compounds during production operations, which is Tier I BACT. Control efficiency varies with type of condenser and type of VOC. Permits issued by the Chemical Section of the Air Permits Division have required the inlet
and outlet temperature of the vapor stream to be monitored and recorded daily. Condensers are sometimes vented to a control device. If the vapors are routed through a condenser to recover liquids and the vapor routed to a flare or to a firebox, the condenser does not need to be tested. If a company claims greater than 80% control efficiency, sampling must be conducted.

Emissions may include VOC (natural gas and condensate groups), BTEX, treatment chemicals, and sulfur compounds (primarily H₂S). In many represented cases in PBR or standard permit registrations, appropriately designed glycol regenerator vents are routed to condensers where the gas streams are compressed and recycled into the plant and the waste streams are sent onto combustion devices or control devices. Consequently, there are no specific emission rates for VOC or sulfur compounds released directly from the condensers listed in the registrations. In addition, limited to no information is available on the usage rates of treatment chemicals (or chemical speciation) that may be used in up stream processing prior to condensation, which may be sent to combustion or control devices. To accurately evaluate the potential emissions, the commission is seeking comments.

The condensed streams are not normally pressurized at a production OGS. As such, any MSS emissions for the condenser may be uncontrolled and undirected VOC, treatment chemicals, and possible H₂S fugitive emission from opening the unit for inspection, cleaning and repair. The condenser will typically be drained of any VOC liquids before opening and only a negligible amount of released air contaminants from evaporation of the wetted surface of the inside walls of the unit will be released. Emissions from MSS may be estimated based on the interior surface area of the unit and the characteristics of the material which it previously contained (this method is used for any similar vessel clean-out). The amount of these MSS emissions is a function of the vessel size, operating pressure of the gas stream processed, and concentration of the air contaminants in the gas stream. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device’s higher temperature, flow rate and stack release height, along with possible sulfur compounds (H₂S converts to SO₂) and products of combustion, and the dispersion characteristics will match that of the control device.

E. Treatment and Processing

Water vapor in natural gas can form hydrates that are an ice-like sludge under certain conditions. When hydrates form in a gas gathering or pipeline system, total or partial blockage of the system may result. To prevent hydrates from forming in a natural gas processing plant, OGS use one or more of several treatment mechanisms: heating the gas stream to above the hydrate formation temperature; adding an antifreeze agent such as methanol or glycol to reduce the hydrate formation temperature; removing water vapor from the natural gas by use of a glycol dehydration unit; dehydrating the gas using a drying agent such as alumina, silica gel, silicon alumina or a molecular sieve; or refrigeration using heat exchangers (lower the temperature) and expansion (drop the pressure to condense water). Other treatment chemicals may be used at OGS, including but not limited to, corrosion inhibitors, surfactants, and scale inhibitors. To ensure an accurate evaluation of potential emissions associated with all types of treatment chemicals is reviewed and covered under the proposed standard permit, the commission is seeking comments on this activity.

1. **Heater Treater:** A heater treater is a horizontal or vertical unit for heating an oil-and-water emulsion to separate and then removing the water and oil and to release any gas
that results. They are generally small vessels less than 500 gallons in size for the
typical OGS and rated at less than 10 million Btu per hour (MMBtu/hr) for the heat
transfer rate from the combustion unit using natural gas, liquid petroleum gas (LPG)
or field gas. A typical heater treater may have a combustion unit rated at 0.5
MMBtu/hr. Their main function is to heat the water to break up the water-oil
emulsions. They have a very small amount of VOC and possibly H₂S fugitive
component emissions for piping associated with the unit. The emissions from the
heater treater vent include products of combustion (NOₓ, CO, VOC, PM, HCHO, and
SO₂) and material handling emissions of VOC and possibly H₂S if the site processes
sour crude oil or gas. Products of combustion are evaluated in the Combustion Units
Section. Material handling releases are covered under Fugitive Components and
should be included in that total count for evaluation.

Tier 1 BACT for heater treater units is the same BACT for boilers and process
heaters. These BACT requirements are listed as follows: (1) heaters with a heat input
capacity less than 40 MMBtu/hr meet the technical requirements of 30 TAC
§106.183, and emissions of NOₓ less than 0.1 lbs per MMBtu heat input; (2) heaters
with a heat input capacity equal to or greater than 40 MMBtu/hr, emissions of NOₓ
less than 0.1 lbs per MMBtu heat input when firing 75%-100% natural gas, emissions
of NOₓ less than 0.015 lb/MMBtu when firing plant fuel gas, emissions of CO no
greater than 50 parts per million by volume, dry (ppmvd) at 3% excess oxygen (O₂),
emissions of ammonia (NH₃) no greater than 10 ppmvd at 3% excess O₂, and opacity
less than 5 percent; (3) heaters with a heat input capacity less than or equal to
500 MMBtu/hr with emissions of NOₓ of 0.01-0.036 lb per MMBtu/hr and 50-100
ppmvd CO at 3% excess O₂; and (4) heaters with a heat input capacity greater than
500 MMBtu/hr with emission of NOₓ no greater than 0.1 lb per MMBtu when firing
75%-100% natural gas, emissions of NOₓ no greater than 0.015 lb NOₓ per MMBtu
when firing plant fuel gas, and 50-100 ppmvd CO at 3% excess O₂.

Planned MSS activities anticipated to be associated with heater treaters cannot be
further evaluated at this time. The commission does not have sufficient information
on the physical design parameters and operational activities which occur at OGS to
accurately predict representative emissions from this MSS activity. Based on similar
combustion devices, there may be an instantaneous, uncontrolled spike in emissions
that occurs for only a portion of the actual hour. Consistent with federal new source
performance standards (NSPS) or maximum achievable control technology (MACT)
for combustion devices, current TCEQ permit reviews do not requires a compliance
demonstration for NOₓ, CO, or VOC during combustion unit startup. Specific data on
this possible spike is scarce. Research by the executive director staff found data
showing that car engines put through the federal emissions tests achieve emissions
steady-state operation and controls (if used) are effective after 5 minutes of operation.
It is reasonable to project this information to larger combustion units, which might
emit at higher levels for 10 – 15 minutes. In the situation where control are used to
reduce emissions, with 50 minutes of controlled operation at 90% NOₓ reduction, and
10 minutes of uncontrolled operation results in an emissions rate for an hour in which
startup occurs as 2.5 times the normal hourly emissions.

2. Methanol Injection: Water vapor in natural gas at high pressures and several degrees
above the freezing point of water (32 °F) can cause serious operating problems by
forming gas hydrates, an ice-like sludge. When hydrates form in a gas gathering or
pipeline system, total or partial blockage of the system may result. Methanol is injected into the gas stream to prevent hydrate formation. Methanol injection into the gas process stream may result in methanol and additional VOC emissions from downstream processing units during production operations. BACT for Methanol Injection is covered under Fugitives Components and Storage Tanks as applicable. Limited to no information is available on the use of methanol injection for OGS in Texas with respect to quantification of process emissions. To accurately evaluate the potential emissions, the commission is seeking comments. Handling of methanol is considered in the section Treatment Chemicals. Maintenance on the piping and pump should result in small methanol fugitive emissions. Maintenance emissions from any methanol storage tank occur consistent with other MSS VOCs from Storage Tanks. The methanol emissions will be considered and reviewed as a treatment chemical. Any MSS emissions resulting from opening the vessels are released and disperse with little or no flow, at ambient temperature, and in an undirected manner.

3. **Glycol Dehydrators:** A glycol dehydrator is used to remove water from natural gas streams, and to prevent the formation of hydrates and corrosion in the pipeline. These units may have uncontrolled emissions of VOCs and H₂S as well as the treatment chemicals (glycols). In addition to using GRI's GlyCalc program to estimate emissions from the glycol dehydrator, sampling can be performed. A sample of the lean glycol and rich glycol can be obtained, an extended analysis performed on both (must obtain BTEX) and a simple mass balance equation can be run to determine the emissions from the reboiler unit. Current Tier I BACT for glycol dehydrator regenerator vents and flash tank vents requires the still vent to be routed to a flare achieving a minimum 98% destruction efficiency or to a firebox achieving a minimum 99% destruction efficiency. Vapors routed to a fuel gas system or sales gas line shall be considered to be 95% controlled. The majority of existing sites reviewed controlled dehydrator emissions, and all were equipped with at least a condenser providing 80% control of the BTEX emissions and a reboiler achieving at least 70% on-line time, with a combined VOC effectiveness of almost 95%. Many of the sites were also equipped to capture the uncondensed vapors from the condenser for use as supplemental fuel. This permit file research also found a representative stack flow rate of 500 actual cubic feet per minute (acfm), 120 °F, diameter of 1 foot, with an exit velocity of 10.6 feet per second (ft/s) and heights ranged from 10 feet to 60 feet.

4. **Molecular or Mole Sieves:** A molecular sieve is a vessel that houses a material containing tiny pores of a precise and uniform size that is used as an adsorbent for gases and liquids. Molecules small enough to pass through the pores are adsorbed while larger molecules are not. Because of this, mole sieves often function as a desiccant. A molecular sieve can adsorb water up to 22% of its own weight. Often they consist of aluminosilicate minerals, clays, porous glasses, microporous charcoals, zeolites, active carbons, or synthetic compounds. They are extensively used at natural gas liquid (NGL) recovery and LPG plants for dehydration and in other applications for removal of contaminants, filtration, and separation. Once the desiccant is saturated with liquid it must be “regenerated.” This is accomplished by passing hot, dry gas through the bed to absorb the liquids. This gas is then condensed and the liquids are separated. Typically, two beds are used – one for drying the gas and the other is in the regeneration cycle mode. Normally molecular sieves are regenerated by passing heated dehydrated process gas through the sieve material, after which the gas is normally recycled as an input to a glycol dehydration unit. The normal production
emissions are fugitive components and products of combustion (NOx, CO, VOC, PM, HCHO, and SO2). Products of combustion from the regeneration cycle are evaluated in the Combustion Units section and material handling releases are covered under Fugitive Components and they should be included in that total count for fugitive emissions and they are evaluated as fugitive components.

Molecular sieves will have a small amount of emissions for MSS whenever the vessel containing the molecular sieve material has to be opened for maintenance operations. Adsorbed gases from the gas stream being processed through the mole sieve material and the gas contained in the vessel will generate emissions when the vessel is opened. Any MSS emissions resulting from opening the vessels containing the mole sieve material for replacement are released and disperse with little or no flow, at ambient temperature, and in an undirected manner. MSS activities associated with these sieves cannot be further evaluated at this time. The commission does not have sufficient information on the physical design parameters and operational activities which occur at OGS to accurately predict representative emissions from this MSS activity. The commission is seeking comments to ensure accurate evaluation of potential planned MSS emissions associated with mole sieves.

5. **Amine Sweetening**: Sweetening is the general term used to describe the removal of sulfur compounds from gas, crude oil or condensate and the weak acid gas CO2, from gas. Most sweetening units use an amine compound to remove sulfur compounds (primarily H2S) from a sour gas. The amine solution has an affinity for sulfur, and absorbs it much like glycol absorbing water. In the sweetening process, the gas stream and the liquid amine are contacted in a countercurrent flow in an absorption column. The sour gas to be scrubbed enters at the bottom and the amine solution at the top of an absorption column providing for countercurrent flow over the packed column material. The liquid amine solution containing the absorbed gases exits from the bottom of the column and is sent to a regenerative unit or reboiler to strip the sulfur compounds. There the amine solution is heated and acid gasses are liberated. At this point the amine solution is now a hot and lean amine solution. Some amine solution is carried over in the liberated gas stream and is recovered using a condenser before the stream is released to the atmosphere or sent to an air control such as a flare. The hot lean amine solution then flows through a heat exchanger where it heats the rich amine solution from the absorption column before it is returned as the lean amine solution to the absorption column. Amine units typically also have flash tanks. For Tier 1 BACT, at a minimum the amine unit regenerator vent and flash tank vent must be routed to a flare, thermal oxidizer, or vapor combustor with a minimum of 98% destruction efficiency.

Different amines have different reaction rates with various acid gases. In addition, amines vary in their equilibrium absorption characteristics with various acid gases, have different sensitivities as to solvent stability, and have different corrosion rates on other materials. Alkanolamines can be divided into three groups: primary amines such as monoethanol amine (MEA) and diglycolamine (DGA); secondary amines such as diethanolamine (DEA) and di-isopropylamine (DIPA); and tertiary amines such as triethanolamine (TEA) and methyl-diethanolamine (MDEA). MEA is the traditional choice for a solvent based upon the highest theoretical amine CO2 absorption capacity of a solvent which is not realized in practice due to corrosion problems. MEA is the least expensive and has the highest vapor pressure of the
alkanolamines solvents. High solvent carryover can occur during CO₂ removal and regeneration. In addition, MEA reacts irreversibly with minor impurities such as carbonyl sulfide (COS) and carbon disulfide (CS₂) resulting in solvent degradation. Foaming of MEA with built-up impurities is a concern. Other amines above going from groups (1) to (3) have lower heat of reaction, lower operating temperatures, lower operating energy requirements and lower steel corrosion rates (due to dissolved CO₂ not necessarily due to the amine). These characteristics are the reason that many custom or proprietary amine solutions are in use.

These sources were reviewed and reasonable worst case parameters were chosen from amine treaters and glycol dehydration units. These vent parameters are thought to be representative of any other kind of stack/vent that is not associated with loading or storage tanks, which have been captured in the “fugitive/loading” category. Stack parameters were derived from a review of PBR and standard permits, and case-by-case NSR permitted sources. A stack flow rate of 500 acfm, a temperature range of 120-200 °F, a diameter of 0.25-1 foot, an exit velocity of 10.60 ft/s, and heights ranged from 10 feet to 60 feet were determined to be a reasonable worst case based on a review of permit files.

Methodologies available for calculating emissions were dependent on available data, resources, and the degree of accuracy required in the estimate. Emission estimates from inputs for programs such as the AMINECalc were generally based on the chemical/physical properties of the material involved, operating data, and physical characteristics of the source equipment. When estimating emissions it is essential that correct data are entered into the program. After reviewing the web sites of several amine unit suppliers and attempting to contact many of the suppliers, only limited responses were received by agency staff. The result of the research indicates amine units were installed on a case-by-case basis depending on the plant’s design, production, and the type of control or recovery process needed. In many cases, amine treaters were used in combination with reboilers or heaters, so additional combustion emissions will result (covered in the Combustion Units section). Resulting sulfur emissions will depend on the concentration of the sour materials handled, but if sweet, emissions were expected to be approximately 0.01 lb/hr and no more than 0.02 tpy SO₂. The remaining VOC emissions from the reboilers or heaters ranged from 0.02 lb/hr to 0.05 lb/hr and 0.10 tpy to 0.30 tpy total VOC. In the standard permit which does not represent a combustion unit, only emissions vented directly from the amine treater, processing and flash losses range from 0.75 lb/hr to 1.5 lb/hr and 3.3 tpy to 4.5 tpy VOCs (including treatment chemicals such as DEA). Limited to no information was available on the usage rates or chemical speciation of amine chemicals. To accurately evaluate the potential emissions, the commission is seeking further comment. Handling of amines is considered in Treatment Chemicals. Atmospheric vessel degassing, maintenance, and startup expectations are the same as listed for separators and dehydrators.

6. **SulfaTreat®**: SulfaTreat® is a registered trademark of the SulfaTreat Company (Chesterfield, MO). SulfaTreat® is a type of solid sweetening process for removal of primarily H₂S. The solid granular product is contained in a pressure vessel and the sour gas is flowed through the vessel until the product is spent. Then, the non-hazardous spent solid product (after washing or cleanup) is removed and sent to disposal. During normal production operations the only emissions are fugitive
component and piping emissions since the reaction occurs in a sealed vessel. VOC, H$_2$S, and PM$_{10}$ emissions may result during maintenance for the replacement of the solid sweetening material in the pressure vessels. The pressurized gases contained in the vessel and associated piping will be vented to the atmosphere through a process vent resulting in VOC and H$_2$S emissions, vented to a thermal destruction where emissions of the products of combustion (NO$_x$, CO, VOC, PM$_{10}$, HCHO, and SO$_2$) and H$_2$S will result, or vented to the atmosphere in an uncontrolled and undirected manner (fugitive dispersion). The magnitude of these emissions should vary depending on the size of the vessel, the operating pressure, if the pressurized vessel is vented to a control before opening, the amount of material on the wetted inside surface, and the amount of liquids and gases remaining before opening. Since these units are commonly pressurized vessels, the uncontrolled degassing activity emissions are most like the dispersion characteristics for Blowdowns, and are included in that section. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device’s higher temperature, flow rate and stack release height, along with possible sulfur compounds (H$_2$S converts to SO$_2$) and products of combustion, and the dispersion characteristics will match that of the control device. Atmospheric vessel degassing, maintenance, and startup expectations are the same as listed for separators and dehydrators.

7. Iron Sponge Units: An iron sponge unit is a solid chemical type of sweetening unit. These units are used to remove H$_2$S from the gas stream. The sour gas stream is routed through pressure vessels or tanks containing iron oxide and wood chips which convert the hydrogen sulfide to water and iron sulfide. Normal production emissions are small amounts of VOC and H$_2$S fugitive component emissions from a small amount of valves, piping, and connections. Sour gas is sent through a bed of hydrated iron oxide. The subsequent reaction with hydrogen sulfide produces iron sulfides and a small amount of water. Limited or no information is available on the use of iron sponge units and associated iron sulfide emissions. The commission is seeking further comment to accurately evaluate the potential emissions.

Planned MSS emissions occur from opening the vessel and replacing the spent iron sponge material. Expected emissions during maintenance would result from de-pressurizing and opening the iron sponge vessel to the atmosphere. The VOC and sulfide emissions, primarily hydrogen sulfide, will result in uncontrolled and undirected emissions (fugitive dispersion). The pressurized gases contained in the vessel and associated piping will be vented to the atmosphere through a process vent resulting in VOC and H$_2$S emissions, vented to a thermal destruction where emissions of the products of combustion (NO$_x$, CO, VOC, PM$_{10}$ and SO$_2$) and H$_2$S will result, or vented to the atmosphere in an uncontrolled and undirected manner (fugitive dispersion). The magnitude of these emissions vary depending on the size of the vessel, the operating pressure, if the pressurized vessel is vented to a control before opening, the amount of material on the wetted inside surface, and the amount of liquids and gases remaining before opening. Since these units are commonly pressurized vessels, the uncontrolled degassing activity emissions are most like the dispersion characteristics for Blowdowns, and are included in that section. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device’s higher temperature, flow rate and stack release height, along with possible sulfur compounds (H$_2$S converts to SO$_2$) and products of combustion, and the dispersion characteristics will match that of the control device.
Atmospheric vessel degassing, maintenance, and startup expectations are the same as listed for separators and dehydrators. Of particular concern with these units is the exposure of the treatment residue to the air and the safety concerns over spontaneous combustion and fire. All reasonable precautions should be taken by operators during maintenance on these units.

8. **Treatment Chemicals:** Treatment chemicals is the general term used to describe all forms (solid, liquid or gas) of chemical compounds that may be used at an OGS and subsequently emitted from various process equipment. These chemical compounds are commonly used in treatment processes, which include but are not limited to: absorption, adsorption, corrosion inhibition, odorizing, lubrication, cleaning, sweetening, defoaming, emulsion breaking, deicing and dehydration.

Examples of treatment chemicals are: amine compounds used for sweetening sour gas; amine compounds used as a solvent to separate CO₂ from field gas; glycols used in dehydration units; and methanol used for prevention of hydrate formation. The calculations of specific emissions from these treatment chemicals are difficult and many of the chemicals are proprietary products. The treatment chemical emissions including MSS will exit the OGS through any emission points: fugitive components, loading/filling vents, tanks vents, process vents, and blowdown or flare sources. Storage and receiving of these treatment chemicals is covered in the Storage Tank section. Emissions from the use of these chemicals are covered in the specific treatment process unit section. In general, many treatment chemicals must remain in the system they are injected into in order to perform the function for which they are intended and designed. Many times the amount (surfactants, scale inhibitors, corrosion inhibitors, etc.) used are the smallest concentration possible to reduce cost, as well as reduce the potential of down-stream issues such as “gunking” which can result from over treatment.

Emissions of treatment chemicals from the process should be negligible due to the nature of the chemicals and their use. The only expected quantifiable emissions from treatment chemicals are expected to be from fugitive components during transfer from storage to process unit. If appropriate fugitive monitoring is performed at an OGS based on site-wide VOC quantification, the concentrations of these fugitive component releases is anticipated to be negligible on a speciated chemical basis.

In other cases, treatment chemicals (for example, glycols and amines) are used in substantial quantities (over 30 thousand gallons per year) and during the treatment process may be subject to temperatures above their boiling points. Emissions from these process units, such as reboilers rated at 100 MMBtu/hr, are products of combustion and VOCs from the materials handled and other contaminants which may be selectively absorbed from the gas stream. Most of the recent patents with glycol and amine gas treatment units deal with methods for minimizing emissions of treatment chemicals. Most reboilers have an air condenser with 80% efficiency control and may or may not have further emissions controls on the emission, with larger rated units normally equipped with thermal air control. Since emissions may vary depending on design of equipment and treatment at the site, the commission is seeking further comment so that an analysis can be performed.
F. Hydraulic Fracturing

An oil-bearing or gas-bearing formation often may contain large quantities of oil or gas, but have a poor flow rate due to low permeability, or from damage or clogging of the formation during drilling. Hydraulic fracturing (also known as fracing) is a technique used to create fractures that extend from the well bore into rock or coal formations. These fractures allow the oil or gas to travel more easily from the rock pores, where the oil or gas is trapped, to the production well. Typically, in order to create fractures, a mixture of water, proppants (sand or ceramic beads), and chemicals is pumped into the rock or coal formation. Eventually the formation will not be able to absorb the fluid as quickly as it is being injected. At this point, the pressure created causes the formation to crack or fracture. The fractures are held open by the proppants, and the oil or gas is then able to flow through the fractures to the well. Some of the fracturing fluids are pumped out of the well and into surface pits or tanks during the process of extracting oil, gas and any produced water, but studies have shown that anywhere from 20-40% of fracturing fluids may remain underground. According to the Interstate Oil and Gas Compact Commission, 90% of oil and gas wells in the U.S. undergo fracturing to stimulate production.

There are many issues associated with hydraulic fracturing. The first area of concern includes hydraulic fracturing chemicals. Coalbed Methane Fracture treatments use anywhere from 50,000 to 350,000 gallons of various stimulation and fracturing fluids, and from 75,000 to 320,000 pounds of proppant during the hydraulic fracturing of a single well. Many fracturing fluids contain chemicals that can be toxic to humans and wildlife, and chemicals that are known to cause cancer. These include potentially toxic substances such as diesel fuel, which contains benzene, ethylbenzene, toluene, xylene, naphthalene and other chemicals; polycyclic aromatic hydrocarbons; methanol; formaldehyde; ethylene glycol; glycol ethers; hydrochloric acid; and sodium hydroxide. Very small quantities of cancer causing chemicals, such as benzene are capable of contaminating both underground water supplies and the atmosphere when these fracturing chemicals are returned to the surface.

One potentially frustrating issue for surface owners is that it may not be easy to find out what chemicals are being used during the hydraulic fracturing operations in their neighborhood. According to the Natural Resources Defense Council, attempts by various environmental and ranching advocacy organizations to obtain chemical compositions of hydraulic fracturing fluids have not been successful because oil and gas companies refuse to reveal this "proprietary information." Another area of concern is hydraulic fracturing chemical disposal. When companies have an excess of hydraulic fracturing fluids, they either use them at another job or dispose of them. Some companies Material Safety Data Sheets (MSDS) recommend disposal of fracturing fluid chemicals be at hazardous waste facilities. However, in many cases these fluids (in diluted form) are allowed to be injected back into underground formations. From a public health perspective for water and air quality, if hydraulic fracturing takes place, the best option is to fracture formations using sand and water without any additives, or sand and water with non-toxic additives. Non-toxic additives are being used by the offshore oil and gas industry, which has had to develop fracturing fluids that are non-toxic to marine organisms.

It has been common to use diesel in hydraulic fracturing fluids. Diesel contains the carcinogen benzene, as well as other harmful chemicals such as naphthalene, toluene, ethylbenzene, and xylene. According to the company Halliburton, “diesel does not enhance the efficiency of the fracturing fluid; it is merely a component of the delivery system.” It is
technologically feasible to replace diesel with non-toxic “delivery systems,” such as plain water. According to the EPA, “water-based alternatives exist and from an environmental perspective, these water-based products are preferable.” Oil and gas wastes are often flowed back to and stored in pits on the surface which are often unlined. Even when lined, the liners can tear and contaminate soil and possibly groundwater with toxic chemicals. As mentioned above, toxic chemicals are used during hydraulic fracturing operations. The same chemicals that are injected come back to the surface in the flowed-back wastes. Furthermore, hydrocarbons from the fractured formation may flow back into the waste pits. A preferable way of storing wastes would be to flow them back into steel tanks. From an ambient air perspective this would be a preferable method of storage, as well since there are potential volatile compounds which may be released from the handling of frac materials.

EPA has recently announced a major initiative to review and assess the appropriate uses and limitations to fractionation materials and techniques. Since this project is underway at the federal level, the commission has not included any additional analysis or requirements in this package.

G. Cooling Towers

Cooling towers are equipment which through the process of direct contact with atmospheric air, reduce the temperature of water used to cool either process equipment or process fluid streams. Cooling tower heat exchanger system refers to the cooling tower and all associated heat changers, pumps, and ancillary equipment where water is used as a cooling medium to which the heat from process fluids is transferred. Each cooling tower in VOC service is considered a facility and multicell towers are represented as a single facility. Although the predominant contaminants in cooling water are VOCs, dissolved gases such as \( \text{H}_2\text{S} \) and ammonia may also be found. All cooling towers operate such that they may emit particulate matter, dissolved solids, or treatment chemicals entrained in the water. Emissions fall into three categories: particulate matter, inorganic compounds, and volatile organic compounds (VOCs, which may contain HAPs). Any cooling tower has the potential to emit all three of these emission types in varying amounts, depending on its service.

Particulate emissions result from the presence of minerals or any dissolved or suspended solids in the cooling water. Air flowing through the tower can entrain water droplets and carry them out of the cooling tower in a process referred to as drift. Once these drift droplets leave the tower and evaporate, they deposit dissolved or suspended solids as fine particulate matter (PM\(_{10} \) or smaller). Cooling towers are generally designed with drift eliminators, typically a mesh or series of angled slates placed above the water. No information is available on the emissions of PM\(_{10} \), although at least one standard permit registration lists 0.05 lb/hr and 0.25 tpy PM from a cooling tower. To accurately evaluate the potential emissions, the commission is seeking further comment. A review of permits for other sources which use cooling towers that is much larger than those expected at OGS indicate that the PM\(_{10} \) emissions should not be a significant source that requires further review, if the cooling tower is designed with drift eliminators.

Inorganic emissions may result from inorganic process fluids leaking into the cooling water or from water treatment chemicals or other additives used in the cooling water system. The air flowing through the tower may strip these inorganic compounds from the water, resulting in emissions. Typical inorganic emissions may consist of chlorinated compounds, brominated compounds, or any other inorganic substance present in the cooling water.
Water treatment chemical emissions also occur, and for purposes of this evaluation, should be estimated and considered similar to all other treatment chemicals. A cooling tower’s emission point is typically a stack (varying heights), releasing air contaminants typically in a range close to ambient conditions, with little to no forced flow. Additionally, limited or no information is available on the emissions of inorganic treatment chemicals. To accurately evaluate the potential emissions, the commission is seeking further comment.

Although some VOC emissions may result from the stripping of organic water treatment chemicals, the primary source of VOC emissions are hydrocarbon-containing process fluids leaked into the cooling water by components of the cooling tower heat exchanger system. Once the hydrocarbon-contaminated cooling water reaches the tower, the VOCs either flash out of the water or are stripped out by the tower’s air flow. This may result in many tons of VOC emissions. Based on a representative group of PBR and standard permit files, the amount of VOC varies widely and ranges from <0.10 lb/hr to 5.00 lb/hr and 0.01 tpy to 11 tpy VOC. With this widely diverse range of emissions, to accurately evaluate the potential emissions, the commission is seeking further comment.

Tier 1 BACT for cooling towers has the requirement to monitor for PM and VOC (including HAPs) emissions and tower designed to reduce drift. For VOCs, cooling tower water should be monitored monthly for VOC leakage from heat exchangers in accordance with the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or another air stripping method approved by the TCEQ Executive Director. Adequate monitoring requires a periodic sample (daily, weekly, monthly) be taken of the inlet water to the tower to determine VOC concentration. An analysis of the outlet water is sometimes required in order to determine the total amount of VOC (and HAPs) emitted. Limiting the solids buildup in the cooling water indirectly limits the particulate matter emitted from cooling towers, as does proper operation of the mist eliminators. Tier 1 minimum acceptable control for PM is the use of mist eliminators and to control PM emissions to ≤0.001% is based on current industry practice for cooling towers, and the commission is seeking comment regarding cooling towers used at OGS since limited information was found in permit files.

In non-attainment or near non-attainment counties, other requirements apply to cooling towers, such as 30 TAC Chapter 115, Subchapter H, Division 2, §§115.760 - 796. In these situations, highly reactive VOCs (1, 3-butadiene, isomers of butene [isobutene, 2-methylpropene, isobutylene, alpha-butylene, ethylethylene, beta-butylene, cis- and trans-isomers of dimethylethylene], ethylene, or propylene) have unique requirements. For this proposal, the control of highly reactive volatile organic compounds (HRVOCs) do not trigger a BACT review, and any facility in those particular ozone areas must comply with the 30 TAC Chapter 115 requirements regardless of this PBR or standard permit, although it is not likely that OGS will have these compounds present. The typical and expected federal standards applicable to cooling towers includes: 40 CFR Part 60, NSPS Subpart KKK, and Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.

MSS activities associated with these units are based in current industry practice. Faulty equipment shall be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs.
H. Gas Recovery Processes

Several processes are used for natural gas liquid (NGL) recovery and liquid petroleum gas (LPG) plants to recover non-methane hydrocarbons from natural gas.

1. **NGL/LPG Cryogenic Expansion:** In the cryogenic expansion process, the gas stream is initially treated by low-temperature separation to remove any residual water in the gas. The dehydrated gas is split, and part of the gas is cooled to -25 °F using residue gas. The remainder of the gas is chilled to 4° F using propane as the refrigerant. The split streams are combined and enter the high pressure separator where the cold liquid hydrocarbons are separated from the gas. The cold liquid hydrocarbons leave the high pressure separator and are reduced in pressure across a valve to lower the temperature to -45°F. This cold liquid hydrocarbon stream provides the heat sink for the upstream heat exchangers used to chill the incoming gas stream. After passing through these heat exchangers, the warm liquid enters the demethanizer. The gas stream from the high pressure separator is expanded to reduce the temperature to -85°F. This gas stream enters the low pressure separator where the hydrocarbon liquids are separated from the gas. The separated liquid stream is circulated as the coolant in the condenser on the demethanizer column and reintroduced as reflux to the demethanizer. The gas stream from the low pressure separator is used to further cool the overhead stream from the demethanizer, and then combined with the demethanizer overhead stream. This combined gas stream is compressed to pipeline pressure. Cryogenic plant emissions primarily include exhaust from the compressor driver (covered in the Combustion Units section), flue gas from the demethanizer reboiler, fugitive component emissions (covered in the Fugitive Components section), and emissions from maintenance activities. For VOC in process vents current Tier 1 BACT requires routing vent streams to a flare, oxidizer, or absorber meeting at least 98% effectiveness.

Expected emissions during maintenance would result from depressurizing and opening the vessel to the atmosphere. The VOC and sulfide emissions will result in uncontrolled and undirected emissions (fugitive dispersion). The pressurized gases contained in the vessel and associated piping will be vented to the atmosphere through a process vent resulting in VOC and H$_2$S emissions, vented to a thermal destruction where emissions of the products of combustion (NO$_x$, CO, VOC, PM$_{10}$ and SO$_2$) and H$_2$S will result, or vented to the atmosphere in an uncontrolled and undirected manner (fugitive dispersion). The magnitude of these emissions should vary depending on the size of the vessel, the operating pressure, if the pressurized vessel is vented to a control before opening, the amount of material on the wetted inside surface, and the amount of liquids and gases remaining before opening. Since these units are commonly pressurized vessels, the uncontrolled degassing activity emissions are most like the dispersion characteristics for Blowdowns, and are included in that section. When MSS emissions are sent to a thermal destruction device, the remaining VOC emissions are released at the device’s higher temperature, flow rate and stack release height, along with possible sulfur compounds (H$_2$S converts to SO$_2$) and products of combustion, and the dispersion characteristics will match that of the control device. Atmospheric vessel degassing, maintenance, and startup expectations are the same as for separators and dehydrators.
2. **NGL/LPG Refrigeration Process**: In the conventional refrigeration process, the inlet gas stream is initially contacted with a lean glycol solution to remove water from the gas stream. The gas/glycol stream is chilled to 30°F to separate the condensable liquid hydrocarbons from the dry gas stream. The liquid hydrocarbons are separated from the rich glycol solution and sent to a stabilizer, where the lighter gas stream is separated from the heavier liquid hydrocarbons. The rich glycol stream is regenerated to remove the absorbed water and recycled to the process. Emissions associated with the refrigeration process include the glycol regenerator off-gas. The flue gas stream from the glycol regenerator reboiler is also typically vented to the atmosphere and may be a source of emissions. Other sources of emissions include fugitive component emissions. Emissions may occur from engines or turbines used for compression in the process and from MSS emissions.

3. **NGL/LPG Absorption Process**: In the absorption process, the wet field gas is contacted with an absorber oil in a packed or bubble tray column. Propane and heavier hydrocarbons are absorbed by the oil while most of the ethane and methane pass through of the absorber. The enriched absorber oil is then taken to a fractionator where the absorbed propane and heavier hydrocarbons are stripped from the oil. The overhead gas product stream from the absorber is then compressed to pipeline pressure. Absorption process emissions include exhaust from the compressor driver (see Combustion Unit section), exhaust gas from the fractionator reboiler, fugitive components (see Fugitive Components section), and vented emissions due to maintenance activities.

4. **NGL/LPG Adsorption Process**: The adsorption process utilizes two or more molecular sieve beds to adsorb all hydrocarbons except methane. The beds are used alternately, with one or more beds onstream while the others are being regenerated by means of heat or steam which removes the adsorbed hydrocarbons. If steam is used, the steam/hydrocarbon vapor stream is condensed and liquid hydrocarbons fed to a fractionation process where the various compounds are separated. Emissions associated with the adsorption process primarily include regenerator vent emissions (if any), exhaust emissions from process heaters associated with the regeneration cycle (see Combustion Unit section), MSS emissions, and fugitive components (see Fugitives section).

Normally, the TCEQ sees represented emissions from NGL/LPG refrigeration, absorption, absorption, or combination of such for only associated process heaters, glycol units, amine units (for CO₂), compressor engines or turbines, piping fugitives, and MSS emissions. Normally, final process vents or streams are represented as residue gas products or natural gas liquids products, not waste gas streams. BACT for process heaters, glycol units, amine units, compressor engines or turbines, fugitives, and MSS is the same as described elsewhere in the background document and as specified in this proposed standard permit. BACT for process vents from NGL/LPG refrigeration, absorption, absorption, or combination of such is for sources of emissions that are not otherwise addressed, as specified in this proposed standard permit.

5. **Heat Exchangers and Refrigeration Units**: Gases are followed by cooling using heat exchangers, and then further cooling by gas expansion or refrigeration dropping the temperature. Initially, water vapor is condensed and removed above the freezing
point or hydrate formation temperature. Further cooling by heat exchangers and/or refrigeration units followed by gas expansion well below the freezing point or hydrate formation temperature, specific VOC gases such as butane and propane (LPG) will condense. These heat exchangers may use part or all of the condensed LPG as the cooling medium for cooling the incoming gas stream. These systems are closed systems and have no process vents. Their emissions are from component fugitives so Tier 1 BACT is historically a LDAR program for fugitives. Limited information is available on the VOC emissions. To accurately evaluate the potential emissions, the commission is seeking further information and assistance from affected stakeholders. Planned MSS emissions are released in an undirected manner from opening the pressurized vessel to the atmosphere, except when they are routed to an emission control device, or a pipeline.

I. Combustion Units

Combustion sources at OGS consist of reciprocating engines and/or gas turbines that power compressors and generators. Other combustion sources are small heaters, heater treaters, boilers, and reboilers. The emissions to evaluate from any combustion source are the products of combustion, that is, NOx, CO, SO2, PM10, and VOC (including HAPs). Formaldehyde (HCHO) is the HAP emitted in the greatest quantity from engines and has the lowest effects screening level (ESL); therefore it can be used for the HAPs evaluation.

Emissions from planned MSS due to shutdown and startup of combustion units should not result in any quantifiable hourly emissions change from standard operation of the combustion units with regard to emissions of CO or NOx. Although there may be transitional and incidental spikes before units stabilize during start-ups (5-15 minutes), overall products of combustion are expected to be within hourly range limits for normal loads during production operations. There are no reasonable controls to be applied during startup and shutdown of combustion units so BACT is to minimize the number and duration of startups and shutdown. Control of blowdowns from associated piping and vessels in petroleum service will be discussed later.

1. Boilers, Reboilers, Heaters and Heater Treaters: Boilers and heaters can vary from a rating of a few thousand Btu/hr for a small heater in a heater treater to large heaters with a rating up to 100 MMBtu/hr or more for heating a gas stream. Most heaters at OGS are less than 40 MMBtu/hr limit and would qualify for PBR §106.183. There are some larger boilers, greater than 40 MMBtu/hr operated and authorized at OGS under standard permits or a new source review permit.

Boilers and reboilers with maximum firing less than 40 MMBtu should easily meet the 0.10 lb NOx/MMBtu/hr BACT requirement when firing natural gas. BACT for CO is 100 ppmv based on assumptions of complete combustion and standard design of units available in the market today. The requirements are the same as 30 TAC §106.183,. Boilers and reboilers with a maximum firing rate greater than 40 MMBtu, should be controlled to 0.04 MMBtu/hr for NOx and 50 ppmv for CO corrected to 3% O2 when firing natural gas. This is Tier 1 BACT and has been the accepted control in past permit reviews for the same process/industry for many years, and technical practicability and economic reasonableness have already been demonstrated. This is also consistent with BACT established with the Air Quality Standard Permit for Boilers. Tier 1 BACT for heater treater units are the same BACT for boilers and
process heaters, including: (1) capacity less than 40 MMBtu/hr, meet the technical requirements of 30 TAC §106.183 and less than 0.1 lbs NOx/MMBtu heat input; (2) capacity equal to or greater than 40 MMBtu/hr, meet 0.01 lb NOx/MMBtu when firing 75%-100% natural gas; 0.015 lb/MMBtu when firing plant fuel gas, 50 ppmvd CO at 3% O₂, 10 ppmvd NH₃ at 3% O₂, and have less than 5% opacity; process heaters less than or equal to 500 MMBtu/hr meet 0.01-0.036 lb NOx/MMBtu and 50-100 ppmvd CO at 3% O₂; and process heaters greater than 500 MMBtu/hr meet 0.01 lb NOx/MMBtu when firing 75%-100% natural gas and 0.015 lb NOx/MMBtu when firing plant fuel gas, and 50-100 ppmvd CO at 3% O₂.

Planned MSS activities anticipated to be associated with combustion units cannot be further evaluated at this time. The commission does not have sufficient information on the physical design parameters and operational activities which occur at OGS to accurately predict representative emissions from this MSS activity. Based on similar combustion devices, there may be an instantaneous, uncontrolled spike in emissions that occurs for only a portion of the actual hour. Consistent with federal NSPS and MACT for combustion devices, current TCEQ permit reviews do not require a compliance demonstration for NOx, CO, or VOC during combustion unit startup. Specific data on this possible spike is scarce. Research by the executive director staff found data showing that car engines put through the federal emissions tests achieve emissions steady-state operation and controls (if used) are effective after about 5 minutes of operation. It is reasonable to project this information to larger combustion units, which might emit at higher levels for 10 – 15 minutes. In the situation where control are used to reduce emissions, with 50 minutes of controlled operation at 90% NOx reduction, and 10 minutes of uncontrolled operation results in an emissions rate for an hour in which startup occurs as 2.5 times the normal hourly emissions.

2. Reciprocating Engines and Turbines: Reciprocating engines can be either rich-burn or lean-burn based upon the oxygen content in the exhaust of the engine and the majority at OGS tend to be spark ignition. Rich-burn engines need to use a catalytic converter to meet the 2.0 - 0.5 g NOx/hp-hr Tier 1 BACT, but new and modified lean burn engines are designed to produce less NOx and can meet the BACT standard without add-on controls. The previous PBR §106.512, had no NOx standard for engines less than 500 hp but Tier 1 BACT in the new standard permit for these engines is 1.0 g NOx/hp-hr. For gas-fired turbines and internal combustion engines, the limits set for VOC, NOx, and CO are based on Tier I BACT. In general, BACT for engines can be found through:

www.tceq.state.tx.us/permitting/air/guidance/newsourcereview/engine/nsr_fac_engine.html and
www.tceq.state.tx.us/permitting/air/nav/air_bact_combustsources.html.

Since the available control technologies for rich burn engines versus lean burn engines were drastically different in cost, the TCEQ Executive Director has created schedules for when each type of engine must meet the lower NOx standards. Rich burn engines typically are upgraded to meet 0.5 g/hp-hr by the use of advanced air to fuel ratio controllers and additional 3-way catalyst modules which are mostly capital cost items. These controls are readily available, easily installed, and according to TCEQ research, the costs are approximately $2000 per ton of NOx controlled. This is within the range of economic reasonableness the executive director uses in BACT determinations. A typical 500 hp rich-burn engine being controlled from the current
§106.512 limit of 2.0 g/hp-hr to the BACT limit of 0.5 g/hp-hr would prevent over 7 tpy of NOx from entering the atmosphere. Another option for these rich-burn engines is to be converted into lean-burn engines. Conversion is typically less cost than extra controls on existing rich burn engines due to the fuel savings that results from lean-burn operation. The commission is considering balancing the cost of upgrading a large number of engines throughout the state with the ease of upgrading, existing engines.

Lean burn engines represent a harder to control class of engines due to the nature of the exhaust composition. 3-way catalysts require relatively little oxygen in the exhaust to properly oxidize CO and VOC while reducing NOx. Lean burn engines have too much oxygen in the exhaust for NOx reduction to occur. The available options for these engines are retrofitting them with newly designed components that would cause less NOx production or replacing the engine with a newer model that produces less NOx. Retrofits are relatively inexpensive but may not apply to all engines. The TCEQ has examined the cost of replacing the engine in order to perform the BACT analysis. While not all engines require replacement, it represents the last available option for control which encompasses all engines in the field. Controlling a lean burn engine to 2.0 g NOx/hp-hr would represent a reasonable control cost for engines that emit more than 2.0 g NOx/hp-hr. Additionally, the newest engines being manufactured emit less than 1.0 g NOx/hp-hr and it is anticipated that engines will be replaced with these new ultra lean burn models. If one follows a typical Tier III BACT analysis, the calculated annualized control costs would be economically reasonable especially considering the life of a new engine (which is the control device also) would far exceed the 10 years normally assumed for control device life in Tier III analyses. The TCEQ understands that the prevalent use of engines within the industry may cause undue financial burden on companies with large numbers of engines that would need to be replaced to meet more stringent limits.

J. Storage and Transfer

Many OGS include: condensate tanks, crude oil tanks, slop/sump oil tanks, pressurized tanks for LPG, speciated (separated by process, e.g., butane, propane, etc.) gas tanks, produced water tanks, amine tanks, glycol tanks, treatment chemical tanks, and fuel storage tanks. Storage tanks used at OGS for condensate, crude oil, slop/sump oil, produced water tanks, fuel storage tanks, and LPG pressurized tanks and speciated gases found from the permits and registrations reviewed were predominately the fixed roof type tanks with uninsulated exteriors surfaces and varied from white to rust colored. The executive director’s staff found information in several current permits, standard permits and PBRs that a typical site would include three crude, one condensate, and one or more water tanks. Larger sites have larger fixed roof tank capacities and may have internal or external floating roof tanks. These findings were also confirmed in an earlier protectiveness evaluation of Standard Exemption 66 conducted in 1997, where it was found that OGS tanks were typically 500 barrel (21,000 gallon) fixed roof storage tanks with a maximum throughput of 500 barrels per day. Fixed roof tanks with internal floating roofs (IFR) were found, along with some external floating roof (EFR) tanks. Both IFR and EFR tanks have lower working and standing emission losses compared to fixed roof tanks without controls so fixed roof tanks were evaluated, representing a worst case scenario for protectiveness review.
Emissions during MSS from various ambient and pressure tanks may include degassing, deheeling, cleaning, and refilling, as well as any other potential air emissions from cleaning, inspection, or repairs associated with planned MSS and will vary based on the operations and physical parameters of any given tank. Since the remaining liquids and gases in atmospheric tanks will be released with no flow rate through existing vents, these emissions should be quantified based on the draining mechanism, physical size of the interior of the tank, and the dispersion characteristics are most like pipeline release emissions. For pressurized tanks, the remaining liquids and gases in the tank will be released with a flow rate through existing vents and these emissions should be quantified based on the draining mechanism and physical size of the interior of the tank. The dispersion characteristics and the pressure of releasing seals for pressurized tanks are most like pipeline or compressor blowdowns. These emissions may be captured, recovered, controlled, or emitted to the atmosphere in an undirected manner.

Based on the commission’s evaluation of actual site conditions and input from stakeholders, many OGS have open-topped tanks and ponds which are integral to site operations. In appropriate situations, these open tanks and ponds are acceptable and will only contribute in a negligible way to the site’s emissions. In other cases, the amount of hydrocarbon liquids entrained in open-topped tanks and ponds may be sufficient to potentially result in a substantial amount of VOCs and H2S emissions as the open-topped tanks or ponds are exposed to the evaporative effects of the sun and wind. Therefore, some reasonable limit is considered above which closed tanks are necessary.

1. **Crude Oil and Condensate Tanks:** Storage tank VOC emissions from crude oil and condensate should be estimated by accounting for Working, Breathing or Standing, and Flash Losses. There are a variety of methods for estimating these emissions and the specifics can be found at: http://www.tceq.state.tx.us/permitting/air/announcements/nsr_announce_9_30_09.html

   Tank color plays an important role in accelerating or minimizing VOC emissions from tank working and breathing losses. An estimate of emissions from working and breathing losses was calculated using Tanks 4.0 and based on the same tank with the same characteristics and throughput, only changing the color of the tank. A typical 500 barrel (bbl) fixed roof crude oil tank painted white (which has a reflective heat effect) has the potential to emit 1.26 tpy of VOC. The same tank was then represented as being brown (such as covered in rust to dirt), and the thermal heat transfer to the contents would result in a potential of 2.19 tpy of VOC, or 74% greater emissions. In other words, a 43% reduction of VOC emissions would occur from changing a brown tank to white.

   An additional demonstration was performed to evaluate the effect of color choice on the emissions from a process vessel, such as a storage tank. The Tanks 4.0 program was used to illustrate the effect of color choice on the working and breathing emissions of VOC, benzene and H2S from a typical oil and gas site condensate storage tank. The H2S and benzene compositions are representative of common permit submittals. While the emissions from flashing within the tank can be of great significance, these emissions are more greatly affected by changes in pressure than temperature. Therefore, emissions from flashing were not represented in this illustration. The conditions of the Tanks 4.0 program were set as follows:
While the argument has been made that solar absorption may not make a significant contribution to the amount of emissions from a process vessel or storage tank, the results clearly demonstrate the paint color used is significant for emissions from working and breathing. Furthermore, painting tanks with a low solar absorption rated color such as white will result in a significant cumulative reduction in statewide emissions of H₂S, benzene, and total VOCs. This has statewide implications especially for counties currently in nonattainment areas or near-nonattainment areas and those of high urbanization. These results are consistent with the TCEQ Air Permits Division Chemical Sections’ previous BACT and BMP determinations for approximately 15 years.

In order to ensure air quality, all facilities authorized must minimize emissions to the greatest reasonable extent, thus the commission has considered proposed requirements to address color for all permanent and temporary liquid and gas tanks and vessels. To effectively minimize the generation of air contaminants, tank color should be white or reflective because potential emissions from any storage or process tank are directly proportional to its color. Tanks need to be painted white or an equivalent reflective color if emissions are more than 5 tpy. Since the solar absorbance of the paint needs to reduce working and breathing (or standing) losses by 40% that would result in a loss of approximately 2 tpy. One estimate submitted by stakeholders claimed as much as $20,000 for the one-time refinishing and repainting a tank. This would meet the standard BACT determination of $10,000 per ton of VOC.

Storage tank vent dispersion parameters assume a pipe diameter of 2 inches (0.17 ft), an exit velocity based on volume of flow through the tank, and an exit temperature.
based on the maximum liquid surface temperature (95°F). These exit parameters are actual parameters; however, they were not used in the modeling since modeling assumed a volume source rather than a point source. Exit velocities are not required for modeling volume sources.

All tanks processing liquids (crude, condensate and water) will also have flash emissions when a liquid goes from a higher pressure to a lower pressure, typically atmospheric pressure. As the pressure on the liquid drops the lighter hydrocarbon compounds dissolved in the liquid are released or flashed off from the liquid. Additionally, some of the compounds that are liquids at the initial pressure and temperature entering the tanks transform from a liquid into a gas/vapor, and are also released or flashed from the liquid. As these gases are released, some of the heavier hydrocarbon compounds in the liquid may become entrained in these gases and will be emitted. The magnitude of the flash gases will increase as the magnitude of the pressure drop increases, and the amount of lighter hydrocarbons found in the liquid increases. Also, the temperature of the liquid and the storage tank will also influence the amount of flashing losses since the ability of a solution to dissolve or hold a gas is related to temperature. If the final temperature is lowered, the final solution can hold more gas which will result in slightly lower flash gas emissions. Consequently, the estimation of flash gas losses becomes a complex process when considering all measured and theoretical properties of the fluids.

Historically, the emission estimates for most OGS tanks have only represented working and breathing or standing losses. However, there are three types of emissions associated from storage tanks used in OGS production processes, flash, working and breathing losses. All OGS processing liquids where the liquid experiences a drop in pressure such as the drop in pressure from a separator to a tank will have flash gas emissions. Recently, technology improvements in infrared (IR) camera technology allows the direct viewing of VOC emissions. A project during the TexAQS II air quality study used this technology and has provided better awareness of the flash gas emission issues to the executive director. The Air Quality Research Project H51C study used the direct approach to quantify flash gas emissions, as described in *VOC Emissions from Oil and Condensate Storage Tanks, Final Report*, by Albert Hendler, et al, published October 31, 2006. This study attempted to determine an emission factor for flash emission from crude oil and condensate tanks in pounds of flash gas per barrel of production under normal operating conditions from 11 crude oil and 22 condensate tank batteries The report shows a large variation in measured emissions factors (1 to 215 pounds per barrel) based on a limited number of sample tank batteries (33) from three area of Texas: Dallas/Fort Worth; Houston/Galveston/Brazoria; and Beaumont/Port Arthur. The report concluded that flash emissions are under reported in emission inventory and permitting.

Due to the large variation of crude and condensate properties throughout Texas, and from site to site, the commission is requiring site specific measurements be taken to estimate flash emissions for permitting purposes. To date, EPA published guidance on flash gas emission determination is that direct measurement techniques provides the most accurate results, but the EPA has no standardized published reference test methods available at this time. The commission has published guidance on the preferred methods for estimating representative emissions from OGS Tanks: www.tceq.state.tx.us/assets/public/comm_exec/pubs/rg/rg360/rg-360-
Two common systems used at OGS are VRUs and flares. Properly sized, designed, and operated VRUs can achieve 95-100% recovery and allow only minor amounts of VOC to escape through fugitive components of the piping. When the VRU is down for maintenance (historically represented as less than 5% of the year or 430 hours), tank and vessel emissions are released to the atmosphere uncontrolled. Flares are often used, but destroy VOCs instead of recovering them. If flares are properly designed, maintained, and stay lit they achieve 98% or better control. When a flare is down for maintenance, tank and vessel emissions are released to the atmosphere uncontrolled.

2. **Produced Water Tanks:** Produced water is any water trapped in underground formations that is brought to the surface along with oil and gas. However, a well which has been deemed absent of crude oil or condensate (also known as dry) does not necessarily imply that hydrocarbons are not still entrained in the produced water. Produced water is by far the largest volume byproduct or waste stream associated with OGS.

In subsurface formations, naturally occurring rocks are generally permeated with fluids such as water, oil, or gas (or some combination of these fluids). These less dense hydrocarbons migrate to trap locations, displacing some of the water from the formation and become hydrocarbon reservoirs. Thus, reservoir rocks normally contain both petroleum hydrocarbons (liquid and gas) and water. Sources of this water may include flow from above or below the hydrocarbon zone, flow from within the hydrocarbon zone, or flow from injected fluids and additives resulting from production activities. This water is frequently referred to as “connate water” or “formation water” and becomes produced water when the reservoir is tapped and these fluids are brought to the surface. The composition generally includes a mixture of either liquid or gaseous hydrocarbons, produced water, dissolved or suspended solids, produced solids such as sand or silt, and injected fluids and additives that may have been placed in the formation as a result of exploration and production activities such as hydraulic fracturing.

As produced water is brought to the surface it is separated from the crude oil and natural gas during the production and separation process. The composition of this produced fluid is dependent on whether crude oil or natural gas is being produced and generally contains a mixture of aromatic hydrocarbons such as benzene, toluene, ethylbenzene, and xylene, in addition to other volatile organic compounds. When the produced water flows from the separator into the storage tank, most of the hydrocarbons will either float to the top of the tank or partially dissolve in the water. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological formation with which the produced water has been in contact for thousands of years, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir. If water flooding operations are conducted, these properties and volumes may vary even more dramatically as additional water is injected into the formation.
Knowledge of the constituents of specific produced waters is needed for regulatory compliance. Oil and grease are the constituents of produced water that receive the most attention in both onshore and offshore operations, while salt content (expressed as salinity, conductivity, or total dissolved solids) is a primary constituent of concern in onshore operations. In addition, produced water contains many organic and inorganic compounds which can be in a variety of physical states including solution, suspension, emulsion, adsorbed particles, and particulates (Tibbetts et al. 1992).

In addition to its natural components, produced waters from oil production may also contain groundwater or seawater (generally called “source” water) injected to maintain reservoir pressure, as well as miscellaneous solids and bacteria. Most produced waters are more saline than seawater (Cline 1998). They may also include chemical additives used in drilling and producing operations and in the oil/water separation process. In produced water, these chemicals can affect the oil/water partition coefficient, toxicity, bioavailability, and biodegradability (Brendehaug et al. 1992).

In addition to formation water, produced water from gas operations also includes condensed water. Studies indicate that the produced waters discharged from gas/condensate platforms are about 10 times more toxic than the produced waters discharged from oil platforms (Jacobs et al. 1992). The chemicals used for gas processing typically include dehydration chemicals, hydrogen sulfide-removal chemicals, and chemicals to inhibit hydrates. Well-stimulation chemicals that may be found in produced water from gas operations can include mineral acids, dense brines, and additives (Stephenson 1992). Volatile hydrocarbons can occur naturally in produced water. Concentrations of these compounds are usually higher in produced water from gas-condensate-producing platforms than in produced water from oil-producing platforms (Utvik 2003). For more information concerning the components of produced water please reference the “White Paper,” prepared by Argonne National Laboratory, which describes produced water from the production of crude oil, natural gas, and coal bed methane.

Traditionally, the commission has been inconsistent in reviewing emissions associated with produced water. Previous guidance related to produced water emissions included:

1. Calculate emissions assuming 100% of emissions from working, breathing, and flash are from crude oil/condensate. This is an overly conservative estimation of emissions from produced water, and will ensure compliance with emissions limitations;

2. Use a reasonable percent or ratio of water-to-liquids production. In many instances, companies assumed 1% of all emissions from working, breathing, and flash (based on total produced water throughput) are VOCs; or

3. Do not quantify or register any VOCs from produced water. Based on observations, monitoring and analysis of available information, the commission has determined that methods (2) and (3) are no longer acceptable for estimating produced water emissions. Method (1) continues to represent a very
conservative estimation of emissions from produced water. Additional methods to quantify VOC and H₂S emissions have been evaluated by the commission.

In order to account for emissions from produced water, an overview of the insoluble relationship between oil/condensate and water taking place within the tank must be addressed. Within the tank two environments exist. The first, as the produced water enters the tank it starts out as a flowing mixture. The second, as this mixture begins to settle it separates out with the oil/condensate rising to the top layer. This relationship can be visualized below. During these two environmental shifts, emissions are being produced. The emissions are accounted for as emissions from working, breathing, and flash (WBF).

All tanks receiving processed liquids (crude oil, condensate and water) will have emissions as the pressure to the tank drops. These emissions will consist of both hydrocarbons and H₂S. During this decrease in pressure upon the liquid, the lighter hydrocarbon compounds dissolved in the liquid are released or “flashed” off from the liquid. Additionally, some of the compounds that are liquids at the initial pressure and temperature of the tanks will transform from a liquid into a gas/vapor, and contribute to the vapor pressure within the tank as emissions from working and breathing. As these gases are released, some of the heavier hydrocarbon compounds in the liquid may become entrained in these gases and emitted. The magnitude of the flash gases will increase as the magnitude of the temperature and pressure drop increases, and as the amount of lighter hydrocarbons found in the liquid increases. Furthermore, the temperature of the liquid and the storage tank will influence the amount of WBF losses since the ability of a solution to dissolve or hold a gas is related to temperature. If the final temperature is lowered, the final solution can hold more gas which will result in slightly lower WBF gas emissions. Consequently, the estimation of WBF gas losses becomes a complex process when considering all measured and theoretical properties of the fluids.

Now that more is known about what type of emissions and how they are produced inside the tank, the relationship between oil and water, and how this affects sampling of produced water, potential VOC and H₂S emissions must be addressed. According to Dalton's Law the total pressure of a mixture of ideal gases is the sum of the partial pressures of each gas component. Ideal gas behavior can be assumed for real gases at moderate pressures. For example, when obtaining a sample of produced water in order to determine flash emissions, the pressure inside the sample container should be equal to the separator pressure. Because of Dalton's Law of partial pressure, the pressure in the sample contains the sum of all hydrocarbons. The hydrocarbon component
can be determined within the sample container accurately once the total vapor
pressure of the sample at the sampling conditions (that is, sample temperature
and pressure) is determined. Vapor pressures of water at the sampling
conditions are published in most chemistry books or in thermodynamics
reference books. What remains when the vapor pressure of water is subtracted
is the sum of total hydrocarbon vapor pressures which are anticipated to be
emitted or “flashed” to atmosphere. The sum of hydrocarbon vapor pressures
divided by total vapor pressure can be used as a factor for adjusting produced
water flash emissions results for VOCs from acceptable calculations methods as
discussed elsewhere. However, the adjustment factor does not account for
weight speciations (that is, the factor is not a weight fraction). VOCs have
heavier too much heavier molecular weights than water, so, for ideal gas, the
factor could be too small, and, therefore yield adjusted emissions of VOCs that
may be underestimated. Furthermore, the factor also does not account for
methane and ethane (not VOCs), likely yielding factor adjusted emissions
results for VOCs that are overly conservative, as methane and ethane typically
make a significant weight contribution to flash emissions of hydrocarbons. The
commission has determined that overall, the factor adjusted VOC emissions
results should be a reasonable representation of emissions from produced water
tanks.

In the past the TCEQ has accepted a percentage of working and breathing
losses. However, since the oil or condensate liquid floats on top of the water
phase, it is the VOCs that are contributing to the partial pressure of the tank.
Therefore when estimating working and breathing losses, the tank must be
assumed to be 100% condensate or oil. Additionally, when the liquid in a water
tank flashes, it can be assumed that the percentage of VOCs entrained in the
water will now contribute to that same partial pressure within the tank as flash
emissions. Hence, in order to achieve an accurate representation of emissions
from produced water 100% of working and breathing loss emissions must be
assumed and combined with the percentage of VOCs entrained in the water.
These results should account for the three known types of emissions associated
with produced water from storage tanks.

Due to the large variation of crude and condensate properties throughout Texas
and from site to site, site specific measurements are required to estimate WBF
emissions from produced water. The EPA’s published guidance on WBF is
that the direct measurement technique provides the most accurate results, but
there is no standardized published reference test method available at this time.
The commission recognizes several methods to estimate emissions, each has
specific constraints. Regardless of which method is used, all supporting data
used to calculate the emissions, including identification of the calculation
method, description of sampling methods, and copies of lab sampling analysis,
must be provided with the emissions estimate.

Tanks 4.0 is a relatively accurate program used to determine working and
breathing emissions within tanks which should be run assuming 100% of the
inputs are VOCs, then combined with a method capable of calculating flash
emissions before submittal as being representative of produced water emissions.
Emission estimation methods for working, breathing and flash may use the following methods for determining emissions: Direct measurement of tank emissions requires sampling and analysis of tank contents, which can be expensive, but the results are relatively accurate; or E&P Tanks Software, V 2.0, using an option that requires site-specific sampling and information. The use of the Geographical Data base option is not applicable. This will require a pressurized liquid and/or gas sample analysis from the separator. In order to determine flash emissions the applicant must subtract stable oil option results from the tank with a separator option. The result should be added to 100% of stable oil option results in order to determine produced water emissions.

Emission estimation methods for flash may use the following methods for determining emissions: There are several different process simulators computer programs (WinSim, Designer II, EPCON, HYSIM, HYSIS, and PROMAX, etc.). The software is accurate when based on a site-specific sample and analysis. Flash emissions must be combined with 100% of working and breathing emissions from Tanks 4.0 before submitted as representative of produced water emissions. Most simulators are not capable of calculating emissions from working and breathing.

1. *AQUAlibrium* was developed for calculating the fluid phase equilibria in systems composed of sweet and sour natural gas (sour gas contains H₂S) and acid gases (hydrogen sulfide and carbon dioxide) in the presence of water. Flash emissions must be combined with 100% of working and breathing emissions from Tanks 4.0 before submitted as representative of produced water emissions.

2. Laboratory measurement of the *Gas-Oil-Ratio (GOR)* from a pressurized liquid sample is a direct laboratory analysis of the flash gas emitted from a pressurized water sample. Flash emissions must be combined with 100% of working and breathing emissions from Tanks 4.0 before submitted as representative of produced water emissions.

3. The *Vasquez-Beggs Equation (VBE)* is a calculation method based on empirical data. The VBE variables must be supported with a lab sampling analysis that verifies the American Petroleum Institute (API) gravity, separator gas gravity, stock tank gas molecular weight, and VOC fraction. If an operating variable used in the VBE calculations falls outside of the parameter limits, the applicant must use another method to calculate flash emissions. Flash emissions must be combined with 100% of working and breathing emissions from Tanks 4.0 before submitted as representative of produced water emissions.

The TCEQ always prefers that the most accurate emission estimates be submitted, based on site-specific, representative worst-case data when possible. Therefore it is preferred that the Vasquez-Beggs method is not used. However, if an applicant can justify any method is capable of representing an accurate estimation of emissions, it will be considered by the commission. If applicants choose to use the Vasquez-Beggs Equation, they should be aware of the risk of potentially underestimating emissions at a site. Regardless of which method is used to calculate produced water emissions, verification of the inputs and calculation methods are required. If at an existing production site, the emission calculations should be determined from site-specific sampling or analysis. If a site is not yet in operation,
information from sister-sites, nearby sites on the same field, or other empirical data may be used with a justification as to why that information is appropriate.

Appropriate controls for produced water tanks are the same as those for other storage tanks, assuming there is sufficient quantity of VOC or H₂S.

3. **Pressurized Tanks:** Due to the fundamental nature of pressurized tanks, the only expected production operation emissions will be fugitive components and should be considered in those component counts. To ensure that pressure is maintained for tank trucks, the federal regulations from the Department of Transportation for trucks rated at 15 pounds per square inch, gauge (psig) or greater requires each tank truck shall be leak checked and certified annually (49 CFR §180.407). There should not be any emissions from pressurized tanks during operations/production. Tier 1 BACT is venting required during tank filling and the vented emissions shall be routed to a control device with a destruction or capture efficiency of at least 98%. In lieu of being equipped to vent to control, the operator may commit to maintaining an operating pressure no less than 50 psig below the set point of the relief valve.

4. **Fuel Storage Tanks:** Fuel storage tanks are commonly diesel, fuel oil, or less frequently, gasoline, used for fuel in combustion engines, processing equipment, mobile sources, and miscellaneous applications. The maximum size tank normally encountered for gasoline is 2,000 gallons. The maximum size tank encountered for diesel or fuel oil is larger at approximately 5,000 gallons. On an infrequent basis, some storage tanks may be converted production tanks with their capacity ranging up to and above 500 barrels. For gasoline, using a maximum vapor pressure for gasoline of 11.0 psia, tank filling rate of 2,000 gallons per hour, and the EPA Tanks 4.0 computer program, a maximum rate of 4.17 lbs/hr of gasoline emissions was calculated for the worst-case hourly tank emissions. For fuel oil or diesel fuel tanks, using a maximum vapor pressure for these materials, a tank filling rate of 10,000 gallons per hour, a vent height of 10 feet, and the EPA Tanks 4.0 computer program, a maximum rate of 0.068 lb/hr of diesel emissions is calculated for the worst case hourly tank emission. Fuel oil emissions will be much less due to the relative vapor pressure of the fuel. The maximum emissions of the two types of fuels are 0.068 lb/hr. Refineries produce high vapor pressure gasoline mainly in the fall and winter and low vapor pressure gasoline in the spring and summer. The EPA tanks program takes into account the ambient temperature when calculating emission. The combination that results in the highest emissions normally occur when the ambient temperature is relatively hot and refineries are producing a relatively high vapor pressure mainly in the fall but may occur in the spring. BACT for fuel storage tanks is the same as the BACT for crude oil and condensate tanks.

5. **Treatment Chemicals Tanks:** Pressurized and unpressurized tanks are used throughout OGS for storing any number of treatment chemicals used at a given site. For example, the storage of amines and glycols, which have been estimated in PBR and standard permit registrations result in <0.01 lb/hr and 0.01 tpy VOC. In one instance, a registration included several 25-bbl lubricating oil tanks with estimated emissions of 0.02 lb/hr and 0.1 tpy VOC. Tanks storing methanol for anti-icing purposes are typically fixed roof tanks generally smaller than two or three thousand gallons in size. The emissions from a small PBR authorized site having one 2,000 gallon methanol storage tank claimed 0.01 lb/hr and 0.03 tpy of VOC. A large
compressor station operating under an oil and gas standard permit can have multiple tanks ranging in size from 150 to 6,660 gallons and emissions from 0.40 to 15.6 lb/hr and 0.01 to 0.13 tpy methanols. Several sites used totes which are considered to have no storage emissions when closed or sealed. A site with several tanks may need to address cumulative emissions. These are generally expected to be small, and sometimes totes are used which are delivered full to the site and taken offsite for refilling. The commission is seeking further comment on these emissions.

6. **Slop/Sump Oil Tanks:*** The following was formulated from a variety of sources. When companies store lubricating oil for engines, they normally claim the storage tanks as engine oil or lube oil tanks. Standby lube oil pump (slop) oil is that oil which results from engine leaks and is collected in a sump or pan. Sump oil is the oil that is collected from the plant’s sump (usually the lowest point on the concrete production slab) and reflective of all sources that discharge or leak hydrocarbons to the sump. Slop tanks and sumps collect hydrocarbon-laced water from a variety of sources, for example, process operations, oil/water separators, lube from engine leaks, oil-water separators, and rainwater. Historically, emissions from these sources have not been quantified because they were considered minor in comparison to the production tanks, and handle low vapor pressure heavy oils that should not result in any significant VOC or H₂S emissions. A few sites were seen to use slop oil tanks as receiving production materials when there was an “overflow” and may have up to 8 tpy of VOC. All 21 sites reviewed claimed a tank as a storage device and used no open sumps as storage container. The majority of emissions from these individual tanks fell into three categories: (1) very low (<0.1 tpy); (2) low (<1.0 tpy); or (3) 1 to 8 tpy of VOC. For the very low category, the represented vapor pressures were below the threshold for quantification as an air contaminant (<0.0002 psia). Most vapor pressures claimed were within the range of gasoline or crude oil vapor pressures. While research of file records showed a number of tanks as having very low annual tank storage emissions, the short term emissions were often as much as 20 lb/hr. Based on this information, these tanks should be considered for any short-term protectiveness review assessment. Tier 1 BACT is the same as crude oil and condensate tanks, assuming sufficient quantity of VOC emissions.

7. **Truck Loading/Filling Operations:*** LPG products are not normally loaded or filled in tank trucks at OGS because these products are typically shipped off-site by high pressure (900 psig) pipeline operations. Loading and filling losses are the primary source of evaporative VOC emissions from crude oil, liquid condensate, produced water, fuel, and treatment chemicals during tank truck loading and filling operations. Loading losses occur from the organic vapors left in the “empty” tank truck when the vapors from the previous load are displaced to the atmosphere by the liquid loaded into the tank truck. Additional loading losses occur by the vapors generated from the new product being loaded. If a vapor balance system is used, additional vapors are transferred to the tank in the vapor balance as product is being unloaded. Based on preliminary information found by the executive director staff only small amounts of VOC were claimed in OGS permit files during loading operations, but the commission is seeking comment regarding the quantity of VOC emitted during loading and in particular loading VOC emission using vacuum tank trucks.

It is assumed that in estimating crude oil, condensate, and produced water loading emissions only one truck is loaded at a time in any one-hour period, since sites with
high production rates will typically deliver directly into a pipeline. However, the Standard Exemption 66 review conducted in 1997 determined that sites with production rates above 1,000 barrels per day had annual truck loading losses of 25 tpy of VOC, which exceeds the general PBR limitations. Since that time, it has become standard industry practice to use pipelines for high production sites. In addition, the standard tank truck capacity is only 180 barrels (7,560 gallons), which makes it uneconomical to use tank trucks. For emission calculations, crude oil with a Reid vapor pressure (RVP) of 5 pounds per square inch, absolute (psia) was used in the AP-42, Compilation of Air Pollutant Emission Factors, Chapter 5.2, Tables 5.2.1 and 5.2.2, and loading emission factors emission equations assuming an empty truck was loaded to full capacity.

Based on a vapor pressure of 5.5 psia at 95.25 °F, the maximum surface temperature of crude oil 5 RVP (based on 1997 Standard Exemption No. 66 Protectiveness Review), in the Midland-Odessa Area according to EPA Tanks program and the AP-42 Chapter 5 Loading Loss (LL) equation, vapor molecular weight of 50, and submerged loading a tank truck in dedicated service would emit 27.8 lb/truck loaded (assuming a tank truck could handle 7,500 gallons based PBR and SP registrations). Splash loading can result in approximately 140% more emissions. Loading condensate with a vapor pressure of approximately 11 psia would double the emissions. Uncontrolled emissions included in some PBR registrations was represented to be 40 to 60 lb/hr VOC, and in some cases with short distances to occupied off-property structures.

BACT is based on permit reviews for VOCs and requires the loading/filling operation to be submerged or bottom loaded with no splash loading. In addition, when loading VOC with a vapor pressure of 0.5 psia or greater at a maximum loading temperature, the displaced vapors must be captured and directed to control. To ensure effective capture of the displaced vapors at chemical plants and refineries the tank trucks are required to pass vapor tightness testing in accordance with the methods described in 40 CFR 60, Subpart XX, Standards of Performance for Bulk Gasoline Terminals, or 40 CFR 63, Subpart R, National Emissions Standards for Gasoline Distribution Facilities, within the past 12 months. While this BACT analysis is based on recent permit reviews, the executive director staff noted that most truck loading existing at OGS under PBR or standard permit had not been closely evaluated. After receiving comments during stakeholders meetings, the executive director staff contacted various petroleum transportation vendors to establish the availability of trucks which would meet the submerged loading requirements of Tier 1 BACT, and found that some operators rely on vacuum tank trucks. For these companies unable to switch from vacuum or splash loading, additional controls would be necessary to achieve emissions equivalent to submerged truck loading for dedicated liquid normal service. It is also unclear how effectively all tank trucks used at OGS across the State could be tested for vapor tightness to insure sufficient capture. Loading loss capture efficiency where vapor tightness cannot be assured is estimated to be only 70% effective. (See AP-42, Transportation and Marketing of Petroleum Liquids, Chapter 5.2, 6/08 edition)

OGS truck loading BACT is being proposed with bottom or submerged fill or controlled equivalent for material with a VOC partial pressure of 0.5 psia or greater at the maximum loading temperature or 95°F which ever is greater. Then, where site
loading has an uncontrolled potential to emit (PTE) equal to or greater than 5 tpy VOC, the displaced vapors must be captured and controlled with device meeting BACT. The control device preferred is a vapor recovery unit that can achieve 95% VOC recovery or destruction control meeting at least 98% is required. This control can be connected directly to the tank truck being loaded or the tank truck vapors can be piped back in a vapor balance to the storage tank being unloaded, if the storage tank is connected to the control device. The vapor tightness testing is not being mandated at this time for BACT, so capture must be estimated at 70% efficiency; but the executive director Staff will study the potential for mandating the testing at adoption and requests comments on the feasibility of compliance across the State. Loading should not be conducted where lines and equipment are obviously in disrepair and leaking. OGS needing additional capture to meet impact requirements will need to retain records on the tank trucks loaded to show they passed leak tightness testing within 12 months prior to being loaded. The capture efficiency should be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water). A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) should be assumed for trucks passing the NSPS-level annual test (3 inches pressure change).

The commission continues to evaluate possible operations and requirements for BACT expectations for crude oil and condensate loading. Emission from loading trucks can be a substantial portion of VOCs from an OGS. The commission therefore expects these emissions to be included in the assessment of the total uncontrolled VOC emissions so that if substantial, these emissions could be routed to a recovery (VRU) or control device (flare) as described above. The commission also has limited information on the various operations and technical specification of vacuum trucks using throughout the diverse oil and gas industry and is requesting comments and technical information on activities and potential emissions from their use.

8. **Underground Storage Caverns**

As a result of stakeholder comments, the commission reviewed several OGS which have underground storage of gas and liquids. A variety of products are currently stored in different types of underground formations across the country. The products stored may be referred to as natural gas, natural gas liquids, highly volatile liquids, or simply hydrocarbon product. The specific compounds stored vary from site to site. There are various reasons for underground storage of hydrocarbons. Long term storage of natural gas is necessary to build up enough supply for the winter (or other time when demand increases). Short term storage is necessary for selling to occur during favorable market conditions. An extra supply is also needed for emergency situations.

Hydrocarbon product storage can occur in salt caverns, depleted gas reservoirs, or aquifers. Statistics from the U.S. Energy Information Administration show that at the end of 2007 in Texas there were 14 salt cavern storage sites, 20 depleted reservoir storage sites, and zero aquifer storage sites. A search of permits issued by the commission resulted in several salt cavern storage sites, but did not result in any depleted reservoir storage sites. The reason for this discrepancy is uncertain; further research on depleted reservoir storage is required.
In general, salt caverns are utilized for short term storage and reservoirs for long term storage due to the fact that product can be withdrawn at a faster rate from salt caverns. Another difference is that the storage capacity of salt caverns tends to be smaller than the storage capacity of reservoirs. In salt dome formation storage, brine (salt water) is used for displacement of the product being stored. The brine also maintains pressure in the formation. When brine is pumped into the bottom of the cavern filled with product, since it is heavier (more dense), it displaces the product out of the cavern. As product enters the storage cavern, an equal volume of brine is displaced and pumped out. The brine is usually stored in an open pond or pit; however, it can also be stored in a tank. Since the brine and product do come into contact with each other, mass transfer does occur to some extent. Some amount of water gets dissolved into the product and some amount of product gets dissolved into the brine. This means that dehydration may be necessary to remove water from the product after it exits the storage cavern. This also means that there will be a certain amount of flash vapors released when the brine is removed from the storage cavern and exposed to ambient conditions. If the entire dissolved product does not flash out of the brine, there will also be evaporative losses (working and breathing losses) from the brine storage area.

The extent of mass transfer between the brine and the product depends on multiple factors. The chemical composition of the product has an effect because of the difference in solubility of each chemical into water and of water into it. The vapor liquid equilibrium is affected by pressure and temperature. The frequency of moving product in and out can also have an effect. Whether or not dehydration of the product is necessary would depend on the water content specification of the customer.

The emission points, equipment, and activities expected to be seen at salt cavern underground hydrocarbon storage sites are:

- Compressors (to move the gas);
- Pumps (to move the liquids);
- Brine ponds, pits, or tanks (to store the brine when it is not underground);
- Brine degassing drum or other similar unit (to separate out hydrocarbons dissolved in the brine; the separated vapors can be flared or recovered);
- Flare, other type of destruction device, or recovery system (to destroy or recover separated vapors to prevent venting to the atmosphere or for upset events);
- Dehydrators (to remove water from the product);
- Piping systems (to direct process streams including incoming and outgoing flow of product and brine to and from storage);
- Fugitives; and
- MSS (well work over or cavern degassing events are done in accordance with Texas Railroad Commission maintenance requirements; the product can be stored, sent to pipeline, or flared as a worst case; high hourly emissions are expected to result).

Most of the emissions associated with normal operating conditions at salt cavern underground storage sites are expected to be similar in nature and amount to typical oil and gas production site operations, especially if brine hydrocarbon flash vapor and MSS emissions are well controlled.

Under emergency conditions emissions could potentially be much greater and could
result in problems. Possible problems associated with underground storage are overfilling, leaks, migration, abandonment, well-head failure, failure of the emergency shutdown valve; fires and explosions are possible outcomes. Because of the amounts and pressures of storage materials, underground caverns are currently the safest and most economical way to meet the storage needs that exist.

A permit from the Texas Railroad Commission is required for any creation, operation, or maintenance of an underground hydrocarbon liquid or gas storage facility. The Texas Railroad Commission Rules are in Title 16 of the Texas Administrative Code, Part 1, Chapter 3. The rules are:

- §3.95 Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations
- §3.96 Underground Storage of Gas in Productive or Depleted Reservoirs
- §3.97 Underground Storage of Gas in Salt Formations

All of these rules have provisions for preventing uncontrolled releases, pollution of fresh water, and danger to life and property. Safety measures are required including an emergency response plan. The permit must be amended if there are changes to the storage zone such as an enlargement of the storage zone or increase in volume stored from what was permitted. Public notice, monitoring, recordkeeping, testing, maintenance are required.

A database search of air permits issued by the commission containing underground storage was performed. Out of eight air permit projects looked at from the search, all were for storage in salt formations. Two projects were looked at in detail, chosen due to the amount of details available in the original permit application.

The first project is for a petroleum products storage facility and pipeline pumping station. The products stored are natural gas liquids (NGL). The storage capacity of the underground salt dome formations is greater than 300,000 barrels (bbl). Brine is stored in three large surface pits. The pump rate for each pit is 9,625 bbl brine/hr and the annual throughput for each pit is 14,000,000 bbl brine/yr.

The emission points associated with this project are:

- Fugitive emissions
- Two Emergency Management Units
- Three brine pits
- One emergency electrical generator
- One fire water pump
- Two fuel tanks
- One maintenance flare
- MSS degassing

The emergency management units (which replaced less-efficient burn tanks) are safety devices that burn vapors by exposing the brine to a pilot flame before it enters the brine pit.

The emissions represented for each of the three brine pits are 4.85 lb/hr and 2.92 tpy of VOC. An emission factor was developed based on testing (2003) which
established a mass of VOC generated for every barrel of brine displaced by product. The testing was done in accordance with EPA method 25D from 40 CFR Part 60, with a few modifications made. Brine pit emissions were estimated by multiplying the volume percent of each component in the product stream by either the hourly pump rate or annual throughput of brine and then by the emission factor for that component.

The second project is for an underground hydrocarbon storage facility consisting of 19 caverns in a salt dome. A variety of petroleum hydrocarbon products and gases are stored including but not limited to n-butane, i-butane, i-pentane, hydrogen, natural gas, propane, ethane-propane mix, butanes-butylenes mix, NGL, propylene, and ethane. There are two separate brine systems, a sweet one and a sour one. The hourly sour brine throughput is 3,400 bbl/hr and the annual sour brine throughput is 5,246,654 bbl/yr. The hourly sweet brine throughput is 4,700 bbl/hr and the annual sweet brine throughput is 22,532,692 bbl/yr.

The emission points associated with this project are:

- Four compressor engines
- One diesel engine
- Two fire pump engines
- Five process heaters
- Four flares
  - One sour brine degassing flare (4.23 tpy VOC, 0.01 tpy H₂S, 0.01 SO₂)
  - One sweet brine degassing flare (3.11 tpy VOC)
  - One main process flare (12.31 tpy VOC)
  - One brine degassing pit flare (0.19 tpy VOC)
- Various miscellaneous tanks
- Four brine ponds
  - Two sour (0.10 tpy VOC each, no H₂S represented)
  - Two sweet (20.09 tpy VOC each)
- Storage pond/brine degassing pit (4.89 tpy VOC)
- Brine Pond Vents
  - Two sour (0.05 tpy VOC each)
  - Two sweet (4.18 tpy VOC each)
- Painting and abrasive blasting
- Fugitives

A knockout drum and flare remove product from the brine before it enters the reservoir (separate knockout drums and flares are used for sweet brine and sour brine). The brine pond vent is the pipe that the brine dumps out of to go into the brine ponds. When brine water needs to be disposed of it is pumped to a brine degassing pit. The brine degassing pit flare is used to ignite any gases entrained in the brine prior to the occasional disposal of the brine.

Emissions from the brine ponds and brine pond vents (amounts shown above) were estimated using a mass balance approach. The flow to the brine degassing flares is also estimated with the mass balance approach. The known stream concentrations and flow rates appear to be from actual measured data; however, no testing results are presented in the application.
In order for an air authorization to be issued, emission estimates are required for all potential sources of emissions. More research needs to be done to determine the best methods for estimating the hydrocarbon emissions from brine and from MSS events. Since there are not currently many underground storage sites permitted by the commission, there is no established emission estimation approach. There is also uncertainty in the amount of underground storage sites that would qualify for permit by rule or standard permit authorizations as opposed to case-by-case permits. If a site does meet the applicable emission limits and other requirements, the site should be able to be authorized by the permit by rule or standard permit as applicable provided that valid emission estimates are provided.

Possible emission estimation methods for the amount of hydrocarbon vapors released from the brine could include both the sampling and the mass balance approaches discussed above. For sampling of the brine, a pressurized sample needs to be taken before it reaches open atmosphere and analyzed so that the amount of flash emissions can be properly quantified.

The reason the commission is authorizing underground storage of gas or liquid hydrocarbons and the associated surface support facilities under the proposed oil and gas PBR and standard permit is because under normal operating conditions emissions are expected to be similar in nature and amount to typical oil and gas production site operations. Under emergency conditions, the emissions could potentially be great and result in a disaster; however, the commission does not have jurisdiction to regulate upset conditions. Instead, the Texas Railroad Commission is the regulatory agency in charge of safety and disaster planning. The commission, therefore, authorizes emissions from underground storage of gas or liquid hydrocarbons and the associated surface support facilities under the Oil and Gas Permit by Rule and Standard Permit only if the storage operation is permitted by the Texas Railroad Commission and in compliance with all applicable Texas Railroad Commission rules.

K. Vapor Recovery Systems

Properly sized, designed, and operated VRUs can achieve 95% recovery and allow only minor amounts of VOC to escape through fugitive components of the piping. When the VRU is down for maintenance (historically represented as less than 5% of the year or 430 hours), tank and vessel emissions are released to the atmosphere uncontrolled.

Based on information from the EPA Natural Gas Partners article, a properly designed VRU system can achieve 95% collection efficiency or greater. A VRU includes a separator, compressor, and piping/hoses. Since a VRU is used to capture BTU-rich vapors from crude/condensate tanks, design requirements dictate the unit is properly sized to handle double the average daily volume within a tank. While the actual volume of crude/condensate within the tank might not actually double; the vapors produced within the tank (resulting from temperature or pressure fluctuations) could increase resulting in greater emissions of hydrocarbons needing control. This increase in emissions can be best defined as emissions from working, breathing, and flash within the tank. For that reason the VRU must be designed to handle this sudden increase or “spike” in emissions. Furthermore, in order for the VRU to work properly, all tank vents, thief hatches, etc. must remain closed at all times. If multiple tanks are routed to the VRU system, they must be manifolded properly.
(piping/hoses). Additionally, the piping that will send the collected vapors into the final control device or back into the inlet must be properly connected.

L. Flares

Flare systems generally are open-flame control devices used for disposing of waste gas streams during both routine process operations, compressor blowdowns for planned maintenance operations, and emergency or upset conditions. In addition to simple, unassisted flares, typical smokeless flare systems include, but are not limited to, the following:

1. **Enclosed Flares/Vapor Combustors**: Enclosed flares are used in disposing of waste gas streams in instances where a visible flame is unacceptable. Applications of this type of flare include chemical processing, petroleum refining and production, and municipal waste gas treatment. These flares may be referred to as vapor combustors and can have more than one burner in the stack.

2. **Steam-Assisted Flares**: Steam-assisted flares are used in disposing of low-pressure waste gas streams when steam is available and practical to use to minimize smoking from the flare. Applications are similar to those of enclosed flares, and they can also be assisted with natural gas, if available on site.

3. **Air-Assisted Flares**: Air-assisted flares are used in disposing of low-pressure waste gas streams when practical or when steam utilities are not available to minimize smoking from the flare. Applications include chemical processing, petroleum refining and production, and pipeline transportation.

In the review of PBR, standard permits, and permitted OGS, the typical flare type found was an unassisted flare. Typical pollutants listed were products of combustion (NOx, CO, VOC, SO2 and PM10) in addition to undestroyed VOC and SO2 from the conversion of H2S. Process flares designed to 40 CFR §60.18 requirements are assumed to achieve 98% control of VOC and include specifications of smokeless operation, minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring. If necessary to ensure adequate combustion, sufficient fuel gas shall be added to make the waste gases combustible.

Flares are expected to handle a potentially rapidly varying waste stream, from no flow to maximum rate and heating value in short periods of time, so some incidental incomplete combustion can occur, and up to 5 minutes of smoking in any 2 hour period has been accepted in both 40 CFR §60.18, state regulations and NSR permits. Acid gas flares as defined in 30 TAC 101.1, Definitions, associated with sweetening processes have a unique potential for visible emissions even when efficiently combusting the waste gas. High sulfur content can be combusted to sulfur trioxide (SO3) which when exposed to water from combustion and a humid atmosphere can form a sulfuric acid (H2SO4) mist that can be visible as a white plume. Exception from the visible emission limitation is allowed for acid gas flares covered under 30 TAC 111(a)(4), which directs acid gas flares to meet the general opacity limitations of 30 TAC 111(a)(1). Note, black smoke from an acid gas flare lasting more than 5 minutes would indicate improper operation of the flare.

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 at sites that are not subject to NSPS. For OGS sites subject to NSPS Part 60, flares must meet the requirements of 40 CFR §60.18 and exceptions for auto ignition would have to be approved in advance in accordance with the applicable rules.

Flares designed to 40 CFR §60.18 criteria should be capable of converting at least 98% or more of the H2S to SO2. By assuming that 100% of the H2S is converted to SO2, this ensures that the maximum amount of SO2 is evaluated as emitted from the flare.

Tier 1 BACT for flares includes a requirement that all flares are designed in accordance with the specifications for smokeless operation, minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR § 60.18. Fuel for all combustion units and flare pilots shall be sweet natural gas or liquid petroleum gas, fuel gas containing no more than five grains of total sulfur per 100 dry standard cubic feet (dscf), or field gas. If field gas contains more than 1.5 grains (24 ppmv) of H2S or 30 grains total sulfur compounds per 100 dscf, the operator maintains records, including at least quarterly measurements of fuel H2S and total sulfur content, which demonstrate that the SO2 emissions from the site do not exceed regulatory standards.

More than 50 permit files and 20 flare specifications were reviewed. In these files, flare energy content ranged from 1,000 to 2,500 Btu/scf from a high Btu source. However, this value varied widely and the only assumption that could be made was any flare reviewed would meet the NSPS standard of 200 Btu/scf. This Btu value represented a conservative estimate in most permit files. Most of the applications reviewed provided the back-up supporting calculations. The flare heights reviewed varied from 20 feet to 200 feet in height, but typically the flare height was 40 feet or less. Flare tip diameters ranged from one inch to 7.75 feet in diameter with a typical diameter less than one foot. The pollutant flow velocities varied from over 70 feet per second to less than 0.10 foot per second. Since such wide ranges were found in the data available, flare parameters such as diameter, velocity, energy content, and temperature were discussed with the Research Manager for John Zinc Company (a flare vendor in Texas) in order to verify typical flare parameters for units used at OGS in Texas. Since the dispersion characteristics of flares and thermal destruction devices are substantially different than process units, it was determined that a separate impacts analysis needs to be performed.

Products of combustion included emissions from both burning a continuous pilot to flared destruction of waste gas streams from an OGS and included the following: 0.05 to 4.5 tpy NOx, 0.10 to 60 tpy CO, and approximately 0.01 tpy PM10. Since sulfur compound releases vary based on sour gas handling processing, the highest reasonable values were noted for review, ranging from < 0.01 to 125 lb SO2/hr. The hourly emissions of VOC also ranged substantially depending on the type and amount of waste streams sent to the flares, within a range of 0.01 to 7.5 lb/hr. A limited percentage of OGS represent routing blowdowns to flares. Input from stakeholders is needed to further evaluate MSS activities which are vented to flares, and what emissions releases would result when an OGS’s flare is not operating, especially if a site continues other processing operations.

As discussed above, it is expected that flared gas streams meet minimum heating value and maximum tip velocity requirements. It is important that these requirements are met to ensure that good combustion/waste gas destruction occurs. Flares achieve good combustion/waste gas destruction by direct flame contact of a gas stream burner flame zone.
The minimum heating value requirement is needed because the heating value of the waste gas (plus assist if needed) must be high enough for good combustion to occur. The maximum tip velocity requirement is needed because achieving good combustion is dependent upon the waste gas having sufficient flame contact time in the burner flame zone, meaning that the waste gas must have a slow enough velocity to allow for that contact time.

Monitoring of heat content and flowrate is not required; however, it is encouraged because it would ensure at all times that flared streams have sufficient heating value and do not have excessive flow. It is expected that the OGS owner or operator is aware what streams are or could possibly be routed to the flare and what the stream heating value and flowrates are. If needed assist gas must be used.

M. Other control Systems and Facilities

Thermal oxidizers are often represented at OGS. These control devices are designed to meet very high VOC control efficiencies, by meeting minimum operating temperature (as measured either in, or immediately downstream of the enclosed combustion region), residence time, and typically 95% to 99.9% destruction efficiency depending on the design and the level of monitoring or testing applied. Thermal oxidizers achieve good combustion/waste gas destruction by routing the gas stream through a high temperature enclosed combustion chamber heated by the separate firing of fuel gas through one or more burners for a sufficient amount of time. Good combustion can be assumed to occur if the combustion chamber temperature is maintained at 1400°F or greater and the waste gas spends at least 0.5 seconds in the chamber. The minimum operating temperature required is 1400°F because that is the generally accepted temperature, based on historical testing, and is necessary for destruction of typical oil and gas production industry waste gas. A different temperature or residence time can be used if justified by testing.

The commission is including thermal oxidizers with destruction efficiencies up to 95% to 99.9%, depending on the level of monitoring or tenting.

Vapor combustors are a category of thermal controls that operate in a similar manner to flares and oxidizers, but do not meet the exact design and operational specifications of either device. Due to the variability in these units, a range of parameters are considered to ensure effective VOC destruction. In general, vapor combustor flame tips should be designed to the same criteria as flares, ensuring sufficient heat content of the waste gas plus assist gas stream for good combustion. The velocity of waste and fuel must be enough to completely combust the waste stream in the flame zone, but not too much that the VOC stream does not remain in the combustion zone. Vapor combustors achieve good combustion/waste gas destruction first by direct flame contact of the gas stream, which has a high enough heating value, in the burner flame zone for a long enough period of time, then additional residence time and sufficiently high temperature is provided in the enclosed combustion region, which is the region between the burner flame zone and the exit point. Vapor combustors need a maximum burner tip velocity requirement because achieving good combustion is in large part dependent upon the waste gas having sufficient flame contact time in the burner flame zone, meaning that the waste gas must have a slow enough velocity to allow for that contact time.

A continuously burning pilot flame during all times waste gas is present (or auto ignition system) is necessary for a properly operating vapor combustor. The operation of these units
should result in no visible emissions (smokeless). Similar to oxidizers, vapor combustors also rely on a minimum temperature to properly operate, as measured either in, or immediately downstream of the enclosed combustion region. The expected temperature of these units is 1400°F, but the executive director does allow operators to establish other temperatures at which the units can operate. Operators may provide manufacturer specifications and test data showing certain parameters and operations are effective in controlling VOCs (if the units will be operated at the same conditions and using the same material). Another alternative is individual unit testing. This approach is used if the units will be operated at different conditions or service from the manufacturer testing. For test results to be accepted for a certain unit, testing must be specific to the same control unit manufacturer, model, size, and the type of vapor stream being controlled. Communication with the appropriate regional office for a pre-test meeting to determine all the appropriate testing criteria is recommended. It is also recommended that the regional office be given the opportunity to observe the actual testing. Testing should be done for worst case scenarios using the most difficult material to combust and highest flow rate. However, testing does not have to occur at each site that degassing is being done provided representative tests have been conducted for each site’s operations. If the site is subject to 30 TAC §§115.541-549, testing must be done in accordance with the approved test methods of 30 TAC, §115.545. If operated properly, vapor combustors achieve a minimum destruction efficiency of 99%.

Since the determination of appropriate operating parameters relies on facility-specific and material-specific sampling, the commission is including only vapor combustors in the proposed standard permit with destruction efficiencies of up to 95% for vapor combustors designed to meet the requirements of 40 CFR §60.18 for flares and with partial or full enclosures.

Additional input is requested from stakeholders on vapor combustor control devices for destruction efficiencies greater than 95%.

N. Planned Maintenance, Startup and Shutdowns

Recent changes to 30 TAC Chapter 101, General Rules, for the first time provide a clear expectation and mechanisms to authorize planned MSS, with a specific schedule depending on Standard Industrial Classification (SIC) code. Although the oil and gas industry’s scheduled date is not until January 5, 2012, the proposed standard permit includes an assessment and evaluation of anticipated MSS activities. It is only under these proposed requirements and limits that MSS is authorized since no previous version of the PBR or standard permit clearly reviewed these emissions. All existing OGS which have claimed historical versions of the OGS PBR or standard permit should use these limits for any MSS releases after the standard permit has been adopted and issued by the commission. It should also be noted that MSS is not required to be authorized and sites will not lose their existing affirmative defense opportunities until January 5, 2012, and therefore any limits or controls are only triggered when an OGS requests authorization for these activities.

All emissions including planned MSS are emitted from the OGS through the equipment or process emission points as fugitive components, loading/filling vents, tank vents, process vents, blowdowns or flares, except for the maintenance emissions described in the following paragraph. These emissions are usually the same in character as production emissions. These emissions, however, are not usually the same in quantity as production emissions, especially on a short-term hourly basis. Although this analysis has estimated and described
MSS emissions from certain production units, the commission requests further MSS information from the industry. Additional information regarding actual or estimated MSS emissions and procedures that would supplement or improve these and any additional descriptions regarding activities at OGS is actively requested. Emissions associated with MSS at OGS are similar in nature to the same sources found at refineries. The executive director staff is currently addressing calculation methodologies and BACT with individual applicants and industry groups for the required deadline of planned MSS reviews at refineries. It is the executive director’s expectation that proposed BACT requirements and emission estimation methods for OGS sources will match those established for refineries for similar sources.

1. **Temporary Maintenance Facilities:** For most industrial sites, maintenance on existing equipment must be performed by temporary equipment brought on-site for short periods of time. In addition, these operations do not typically occur simultaneously with normal production operations or have similar emissions. The proposed evaluation also focused on limitations that are equivalent to de minimis facilities and activities, which by definition do not constitute or contribute to a condition of air pollution.

Temporary or permanent maintenance facilities include abrasive blasting, surface preparation, and surface coating operations on immovable, fixed structures. Historically, the commission has authorized these maintenance activities under 30 TAC §106.263, (Routine Maintenance, Startup, and Shutdown of Facilities and Temporary Maintenance Facilities) if the blasting, surface preparation, and coating supplies and equipment are taken to the object fixed in place and there is no practical means of moving the object to a designated area for surface preparation. If an object can be taken to a designated area, then other PBRs such as §106.433, (Surface Coat Facility), and §106.452, (Dry Abrasive Cleaning), would apply. Other portions of this proposal cover engines and turbines during testing and repair. Since 1995, the commission has allowed testing of an engine or turbine to be considered as part of the maintenance on that unit and authorized emissions associated with testing under §106.263 when it occurs at a maintenance shop or business. Also included are engines, compressors, pumps, and associated purging which are associated with maintenance activities. These additional units are frequently seen in the field when maintenance activities occur and have historically been authorized under §106.263. The use of §106.263 is not intended for replacement units, but only additional temporary facilities which are needed during maintenance. Finally, temporary piping and associated facilities are needed to bypass a unit or section of pipeline during maintenance situations is covered because as such bypass lines reduce or eliminate emissions during maintenance. Long-term emissions for these temporary facilities are proposed to be limited to a cumulative, site-wide, rolling 12-month basis to prevent significant accumulation of emissions authorized by these conditions. For all of these types of facilities and operations associated with planned MSS, the executive director expects OGS to use those specific PBRs which cover the referenced activities and combine those emissions with other, permanent facilities to demonstrate compliance with applicable general limits of 30 TAC §106.4, Requirements for Permitting by Rule, or §116.611, Registrations to Use a Standard Permit.
2. **Compressor Blowdowns:** Compressor blowdowns allow emissions to be released through a stack or opening when an OG temporarily vents a gas compressor. To establish typical parameters and expected emissions from this activity, numerous PBR, standard permit, and permit files were reviewed. Three sites with the highest MSS blowdown emissions were reviewed in order to select modeling parameters. The sources had release heights of 20 feet, exit diameters ranged from 0.5 to 6 feet, average exit velocities claimed varied from 1.4 to 140 ft/sec, and the exit temperature was assumed to be equal to the ambient temperature. Emissions from blowdowns range widely depending on the amount of piping and the pressure and how much vapor or liquids remain in pipes and equipment prior to shutdown of compression at an OGS. The frequency of blowdowns also depends on the operational conditions of any given site. Typical representations for PBR and standard permit registrations range from 20 lb VOC/hr to over 200 lb VOC/hr uncontrolled for “blowdowns” and annual emissions ranged from 0.1 tpy to 15 tpy. Based on a Tier 2 evaluation of BACT for compressor blowdowns, if the total uncontrolled VOC emissions from compressor blowdowns and other high potential uncontrolled sources at the site equals 10 tpy or greater, then these emissions should be routed to a control or recovery device with a destruction or capture efficiency of at least 95% (flares or VRUs). Operators can also reroute blowdown vent streams to blowdown casings and then ramp the pressure up, routing the stream back into the system. In many cases, blowdowns can only be recovered to a low pressure system only, but new techniques can allow this recovery to occur in high pressure systems.

3. **Pipeline releases:** Pigging operations are conducted to assist in product transfer and product separation, as well as for maintenance activities. A pig is a physical device which varies in size and can be made of a variety of materials such as plastic, urethane foams, and rubber. Pigs can also be solid, inflatable, foam, or made of a viscous gel. The specific design of a particular pig depends upon the pipeline as well as the purpose of the pigging operation. Three types of pigging operations occur in pipelines at OGES field production and processing sites: product transfer, product separation, and maintenance. Pigging following product transfer is used to remove residual product from the pipeline after loading occurs. Pigs can also be used for product separation to transport more than one product, such as oil, gas, or condensate as well as for maintenance activities such as pipeline cleaning, gauging, or dewatering. During pigging operations, a pig is inserted into the pipeline and is forced through the pipeline by a compressed gas, such as nitrogen or pumped down a pipeline by the products being handled. When the pig gets to the end of the line, it is trapped in a receiver. The gas is then bled off from behind the pig. The initial depressuring of the pipeline, if vented to the atmosphere, rather than to a flare or incinerator, may involve uncontrolled blowdown emissions primarily consisting of VOC, HAPs, and H2S. The emission rate in a blowdown is a function of the product in the pipeline, the amount of piping and equipment manifolded into the system, line pressure, the frequency of equipment discharges, and the blowdown system controls employed. The frequency of blowdowns also depends on the operational conditions of any given site. Based on a Tier 2 evaluation of BACT for compressor blowdowns, if the total uncontrolled VOC emissions from compressor blowdowns and other high potential uncontrolled sources at the site equals 10 tpy or greater, then these emissions should be routed to a control or recovery device with a destruction or capture efficiency of at least 95% (flares or VRUs).
4. **Tank and Vessel Degassing**: MSS requirements for depressurizing, draining, and degassing process equipment, equipment opening, tank and fugitive component maintenance, and vacuum truck loading continue to be evaluated based on the refinery and chemical plant permit reviews. All OGS MSS applications represented control of very high vapor pressure compounds, where vapor pressures equal or exceed 14.7 psi. Further input is requested on appropriate operations and control of emissions during degassing.

5. **Other MSS**: Various other activities occur at OGS to ensure equipment is kept in good working order. These include many incidental lubrication and similar actions which result in negligible releases of air contaminants, such as: lubrication oil and oil filter changes for engines and turbines; sparkplug changes; replacement of oxygen sensors; compression checks; lubrication oil leak repairs; engine overhauls; boiler refractory replacements; boiler and heater cleanings; heat exchanger cleanings; and pressure relief valve testings. Other maintenance activities occur to ensure the process equipment operates at optimum levels by replacing treatment chemicals, catalysts, and filters. In all of these circumstances, the executive director does not anticipate any quantifiable emission releases which are otherwise not accounted for above.

**O. Combined Emission Control**

Oil and gas sites can have a variety of facilities that when combined have a significant number process vents emitting VOC in volumes and concentrations that are worth recovering the resource or become reasonable and appropriate to control. Where facilities are generating waste gas streams that contain more that 1% VOC and their combined emissions have the potential to emit more than 25 tpy of VOC, vapor recovery or oxidation or combustion control is mandated for these streams. The TCEQ strongly encourages vapor recovery where plausible and the gas capture and use is possible (i.e. gas pipelines or storage is available). Where recovery is not possible oxidation or combustion control of waste gas streams with more than 1% VOC is being mandated for the smaller streams. The cost of flare control has been determined to be reasonable for storage tank and loading streams of 5 tpy or more. With appropriate sizing a flare or other combustion control can accommodate routing of multiple smaller streams to the same control for the cost of piping or piping with a fan or compression to direct the gas.

**P. Exclusions**

The following units and operations were excluded for various reasons for consideration under the standard permit:

1. **Sulfur Recovery Units**: (SRU) were not covered because it was discovered that when the SRU was pulled out of service for maintenance operations that the emissions typically exceed the PSD significance levels, and can not be authorized by a PBR or standard permit. The only way to prevent triggering PSD for the site is for the OGS to build a redundant SRU to switch over during maintenance operations. Since the reviewed permitted OGS did not reveal any dual SRU units, it was concluded by the executive director staff that the industry was reluctant to invest in the capital outlay, and consequently SRUs were excluded from the evaluation.
2. **Carbon Dioxide Hot Carbonate Processing Units** were excluded since the executive director staff was not able to obtain sufficient processing and emission data for production, or maintenance, startup, and shutdown emissions on these units from applications it reviewed. As a result the executive director staff was not able to evaluate these units. The commission requests comments on carbon dioxide hot carbonate processing units and will evaluate accordingly.

3. **Water Injection Facilities** are subsurface facilities that are involved in waste disposal activities, which are beyond the scope of the OGS production processes at the sites. In EPA’s determination regarding site definition, it was limited to surface equipment, and this further supports the executive director’s position.

4. **The Transfer of Liquefied Petroleum Gases, Crude Oil, or Condensate by Railcar, or Marine Barges** was also excluded as these operations were not found at sites in our review because larger OGS use pipeline transfer for economic reasons.

5. **Sour Water Strippers** were not evaluated for protectiveness since they are associated with sulfur recovery units, and SRUs have been excluded from this standard permit. Sour water strippers are used to remove H₂S, a major form of sulfur compounds in sour petroleum from the water before handling and disposal were not evaluated.

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**VI APPLICABLE STATE AND FEDERAL REGULATIONS**

**A. State Regulations**

All facilities and sources in Texas must comply with various requirements in 30 TAC Chapter 101, General Rules. The commission notes the most common parts of this chapter affecting OGS are Subchapter B, Emission Events, Reporting, and §101.4, Nuisance. Potential nuisance conditions do not only occur with oil and gas from odors or smoke, but in many cases in-plant roads work areas traffic and activities may generate substantial dust problems. Where necessary, operators are reminded that sufficient care and controls must be taken with all material handling and traffic which may cause dust so as to not cause a nuisance.

All sites in Texas must comply with opacity limitations in 30 TAC Chapter 111, Control of Air Pollution from Visible Emissions and Particular Matter, including the 20% opacity requirement and appropriate compliance demonstrations.

All OGS, especially sour sites, must ensure compliance with the ambient air standards in 30 TAC Chapter 112, (Control of Air Pollution from Sulfur Compounds). The property-line determinations must show compliance with SO₂ property-line standards ranging from 715 µg/m³ to 1021 µg/m³ (0.28 ppmv in Galveston or Harris Counties, 0.32 ppmv in Jefferson or Orange Counties, and 0.4 ppmv for the remainder of the state) and H₂S standards range from 108 µg/m³ to 162 µg/m³ (depending on impacts occurring a residences, businesses or on commercial property). These standards were evaluated and this proposal relies on using the most stringent of standards so that a simplified set of acceptable emission tables could be developed. Sulfur recovery under Chapter 112 is not addressed here as no SRUs will be allowed under the standard permit.

In addition, sites in non-attainment and near non-attainment counties must comply with various standards in 30 TAC Chapter 115 for VOCs and 30 TAC Chapter 117, (Control of...
Air Pollution from Nitrogen Compounds) for NOx. The affected areas include the following: Houston/Galveston/Brazoria (HGB) - Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, Waller Counties; Dallas/Ft. Worth (DFW) - Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, Tarrant Counties; Beaumont/Port Arthur (BPA) - Hardin, Jefferson, Orange Counties; and East Texas counties (ETC) - Anderson, Brazos, Burleson, Camp, Cass, Cherokee, Franklin, Freestone, Gregg, Grimes, Harrison, Henderson, Hill, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Titus, Upshur, Van Zandt, Wood Counties.

The requirements in 30 TAC Chapter 115 include: Subchapter B, Storage of Volatile Organic Compounds Vent Gas Control; Subchapter C, Loading and Unloading of Volatile Organic Compounds; Subchapter D, Control of Volatile Organic Compound Leaks from Transport Vessels; and Subchapter D: Fugitive Emission Control in Natural Gas/Gasoline Processing Operations. Depending on the vapor pressure at which certain liquids are stored or transferred, and the quantity of liquids being processed, for both crude and condensate, different control devices are required to reduce or eliminate air contaminants. Further, the site’s location will require more stringent controls if located in serious or severe non-attainment areas. Like other state regulations, there are exemptions depending on specific operations at a given site.

Those OGS which have combustion devices and are located in non-attainment and near non-attainment counties must comply with requirements in 30 TAC Chapter 117. For stationary, reciprocating internal combustion engines, NOx emission limits for specified areas vary and depend on several criteria: the type of fuel being used, the horsepower of the engine, and the date of modification (modification of an existing facility as defined under 30 TAC §116.10), reconstruction, or relocation. The compliance date, which determines when a given engine is subject, will also vary. Additionally, there are different NOx emissions limits based on whether a site is considered major or minor. Again, there are exceptions for when engines in a specified area are exempted from the provisions of Chapter 117.

There are also Chapter 117 restrictions that apply to water heaters, small boilers, and process heaters, which are covered under Subchapter E, Multi-Region Combustion Control, Division 3. There are applicable dates and operating parameters which will cause certain equipment to become applicable to these provisions, including but not limited to maximum Btu capacity, manufacture date, and heat output. Under Subchapter E, Division 1, Electric Generating Units are subject to limitations based on installation date, use for compensation, use in turbine exhaust ducts, and area of location.

Each provision under Chapter 117 will require different methods of reporting and recordkeeping as well and will vary depending on location and the subchapter under which a company or facility is subject.

On February 24, 2010, the commission adopted changes to 30 TAC Chapter 114, (Control of Air Pollution from Mobile Sources) to expand the Emission Reduction Incentives Grants Program of the Texas Emissions Reduction Plan. These changes include projects related to engines used for natural gas recovery. This means if an engine can be retrofitted or replaced to reduce NOx emissions and the engine qualifies for the program, a certain amount of reimbursement is possible based on the amount of reductions achieved. The program is applicable to 41 counties in Texas, which are nonattainment counties or affected counties.
B. Federal Ambient Standards

National Ambient Air Quality Standards (NAAQS) must also be complied with at a site’s property line. There are numerous NAAQS for air contaminants which are released at OGS. As appropriate, standards are converted from the promulgated averaging period to an equivalent 1-hour basis for use with the emission tables. Variables for SCREEN modeling were relied upon for this conversion (30-min same as 1 hr, 3-hr adjusted by 0.9, 8-hr by 0.7, 24-hr by 0.4, and annual by 0.08). Specifically of interest is the 1-hr NOx standard of 188 µg/m³ (100 ppmv), which became effective on April 12, 2010. Other pollutants with NAAQS and relevant averaging periods are included in the table below.

C. State Property-Line Standards and NAAQS

Applicants must demonstrate compliance with the most restrictive of all applicable state and federal property-line standards for the following pollutants: H2S, SO2, CO, PM10, and NOx. Based on the discussion above, the assessment of applicable limits is summed in the following table:

<table>
<thead>
<tr>
<th>State and Federal Regulatory Standards</th>
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<tbody>
<tr>
<td><strong>Compound</strong></td>
</tr>
<tr>
<td>H2S</td>
</tr>
<tr>
<td>SO2</td>
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<tr>
<td>NOx</td>
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<tr>
<td>CO</td>
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<td>PM10</td>
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<td>PM2.5</td>
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The designated value (bolded) that should be used for the hourly emission rate limits is based on the lowest (controlling) modeling concentration for any standard, assuming continuous emissions of that air contaminant. For H2S, the regulatory standards are all based on 30-min averages, so the worst-case 1-hour equivalent should be used for a protectiveness and compliance determination. With substantial variability in time periods during which SO2 emissions occur, if all emissions can meet the most restrictive designated value of 196 µg/m³, no further review should be needed. It should be noted that EPA announced, and is expected to publish a new hourly NAAQS of 75 ppm. When the new standard becomes effective after this standard permit is proposed or adopted, all facilities must be able to demonstrate compliance with that standard. CO was initially evaluated and determined to have expected impacts well below the NAAQS so no further evaluation was necessary. PM10 and PM2.5 emissions from OGSs are typically small in magnitude, and no further evaluation was necessary after an initial evaluation. Additionally, PM2.5 emissions at OGSs are due to combustion. Details of the regulatory evaluation by the commission are discussed later in this document.

D. Other Federal Regulations

Federal requirements applicable to facilities at OGS can be found in both 40 CFR Parts 60 and 63 (NSPS and MACT requirements). Since the OGS PBR and standard permit were last revised, several federal standards have been adopted for facilities at OGS. The proposed
PBR and standard permit are consistent with these new requirements, including 40 CFR Part 63, Subparts HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities and Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants from Stationary Reciprocating Internal Combustion Engines. Sources subject to MACT standards are classified as either major sources or area sources. Major sources are sources that emit 10 tpy of any of the listed individual HAP, or 25 tpy of a mixture of HAPS. These sources may release HAPs from equipment leaks, when materials are transferred from one location to another, or during discharge through emission stacks or vents. Area sources consist of smaller-size facilities that release lesser quantities of HAPs into the air. Area sources of HAPs are not major source of HAPs. Though emissions from individual area sources are often relatively small, collectively their emissions can be of concern, particularly where large numbers of sources are in heavily populated areas.

1. **Oil & Natural Gas Production (MACT HH):** National Emission Standards for Hazardous Air Pollutants for Source Categories from Oil and Natural Gas Production Facilities limits emissions of HAPs from oil and natural gas production and natural gas transmission. For major oil and natural gas production sites, the rule requires controls for process vents at certain size glycol dehydration units, tanks with flashing emission, and certain fugitive component emission sources at natural gas processing plants. For area source requirements, this MACT covers triethylene glycol (TEG) dehydration units at production sites processing 3 million standard cubic feet per day, or sites with benzene emissions of one ton per year or more. This subpart requires 95% control for dehydration units located in urbanized areas plus the areas included by the two mile offset and urban clusters as identified in the U.S. Census Bureau's 2000 Census. Sites are subject to emissions reduction requirements in this final rule if you own or operate a TEG dehydration unit with an actual annual average natural gas flow rate equal to or greater than 3 million standard cubic feet per day (MMscfd) and with benzene emissions equal to or greater than 1 tpy. Source having less than these values, have no federal controls required.

2. **Transmission and Storage (MACT HHH):** The primary HAPs of concern are benzene, toluene, ethylbenzene, mixed xylenes (all three isomers), cumulatively referred to as BTEX, and n-hexane. Implementation of these regulations is focused on benzene (i.e., emission cutoffs or exemptions are based on benzene). These regulations establish control requirements for HAPS emissions from certain glycol dehydrators located at major sources in the transportation and storage industry; sites without dehydrators are not covered by Subpart HHH. The transportation and storage standards apply to sites that are major sources of HAPs, but only require controls on glycol dehydrators above certain emission and throughput thresholds. For this standard, all HAPS emission points at the site must be considered in the determination of a major source. This regulation requires control of glycol dehydrator emissions at 95% for units that have single HAP emissions of $\geq 10$ tpy (BTEX, formaldehyde) or $\geq 25$ tpy total HAPs.

3. **Stationary Reciprocating Internal Combustion Engines (RICE) (MACT ZZZZ):** Recently EPA promulgated revision to 40 CFR Part 63, Subpart ZZZZ, currently applicable to new and reconstructed stationary RICE and to existing stationary RICE greater than 500 hp located at major sources. EPA added requirements for: existing compression ignition, stationary RICE less than or equal to 500 hp located at major
sources and existing compression ignition, stationary RICE located at area sources. The final rule regulates emissions of HAPs. Available data shows that several HAPs, formed during the combustion process or which are contained within the fuel burned, are emitted from stationary engines. The HAPs which have been measured in emission tests conducted on diesel fired stationary RICE include: 1, 3-butadiene, acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde, n-hexane, naphthalene, polycyclic aromatic hydrocarbons (PAH), styrene, toluene, and xylene. Metallic HAP from diesel fired stationary RICE that have also been measured, and include: cadmium, chromium, lead, manganese, mercury, nickel, and selenium. The final rule will limit emissions of HAP through emissions standards for CO for existing stationary compression ignition RICE. CO has been shown to be an appropriate surrogate for HAP emissions from compression ignition engines. Because testing for CO emissions has many advantages over testing for HAP emissions, CO emissions were chosen as a surrogate for HAP emissions reductions for compression ignition stationary engines. Consequently, EPA is finalizing emission standards for CO for stationary compression ignition engines in order to regulate HAP emissions. In addition, EPA is promulgating separate provisions relevant to emissions of metallic HAP from existing diesel engines. In addition to reducing HAP and CO, the rule will result in the reduction of PM emissions from existing stationary diesel engines. The after-treatment technologies expected to be used to reduce HAP and CO emissions also reduce emissions of PM from diesel engines. The final rule also requires the use of ultra low sulfur diesel (ULSD) for diesel-fueled stationary non-emergency compression ignition engines greater than 300 HP with a displacement of less than 30 liters per cylinder. This will result in lower emissions of sulfur oxides (SOx) and sulfate particulate from these engines by reducing sulfur content in fuel.

4. Petroleum Liquids Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and Prior to May 19, 1978 (NSPS Subpart K): Subpart K establishes standards for volatile organic compounds from petroleum liquid storage vessels. The rule applies to storage vessels containing petroleum liquids with a storage capacity greater than 40,000 gallons for which construction, reconstruction, or modification commenced after June 11, 1973, and prior to May 19, 1978. Vessels storing petroleum liquids with a true vapor pressure equal to or greater than 1.5 psia, but less than 11.1 psia must be equipped with a floating roof, vapor recovery system, or an equivalent control. Vessels storing petroleum liquids with a true vapor pressure greater than 11.1 psia must be equipped with a vapor recovery system or an equivalent control. The owner or operator must maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of the liquid. Vessels storing petroleum liquids with a maximum Reid vapor pressure less than 1.0 psia, or vessels equipped with a vapor recovery and return or disposal system are not required to comply with the monitoring requirements. Storage vessels located at drilling and production sites for petroleum or condensate prior to custody transfer are not required to comply with the subpart.

5. Petroleum Liquids Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978 and Prior to July 24, 1984, (NSPS Ka): Subpart Ka establishes standards for volatile organic compounds from petroleum liquid storage vessels. The rule applies to storage vessels containing petroleum liquids with a storage capacity greater than 40,000 gallons for which construction, reconstruction, or modification commenced after May 18, 1978 and
prior to July 24, 1984. Vessels storing petroleum liquids with a true vapor pressure equal to or greater than 1.5 psia but less than 11.1 psia must be equipped with an external floating roof, a fixed roof with an internal cover, a vapor recovery system that collects all vapors and gases from the tank and a vapor return or disposal system, or an equivalent control, and meet the particular requirements specified for each control method in the rule. Vessels storing petroleum liquids with a true vapor pressure greater than 11.1 psia must be equipped with a vapor recovery system that collects all vapors and gases from the tank and a vapor return or disposal system that reduces emissions by at least 95%. The owner or operator must comply with specific testing requirements and procedures, monitoring requirements, and maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of the liquid. Vessels storing petroleum liquids with a maximum Reid vapor pressure less than 1.0 psia, or vessels equipped with a vapor recovery and return or disposal system are not required to comply with the monitoring requirements. Storage vessels with a capacity less than 420,000 gallons located at drilling and production sites for petroleum or condensate prior to custody transfer are not required to comply.

6. **Volatile Organic Liquids Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (NSPS Kb):** Subpart Kb establishes standards for volatile organic compounds from petroleum liquid storage vessels. The rule applies to storage vessels containing petroleum liquids with a storage capacity greater than 75 cubic meters (approximately 19,800 gallons) for which construction, reconstruction, or modification commenced after July 23, 1984. Depending on the true vapor pressure of the petroleum liquid being stored and the storage vessel’s capacity, the storage vessel must be equipped with a fixed roof in combination with an internal floating roof, an external floating roof, or a closed vent system and control device, and meet the particular requirements specified for each control method in the rule. The owner or operator must also comply with specific testing requirements and procedures, monitoring requirements, and reporting and recordkeeping requirements. Certain storage vessels are not required to comply with the subpart due to their capacity, the true vapor pressure of the compound stored, or the industry type at which they are located.

7. **Stationary Gas Turbines (NSPS GG):** Subpart GG establishes standards for nitrogen oxides and sulfur dioxide from stationary gas turbines. The rule applies to all stationary gas turbines with a peak load equal to or greater than 10 million Btu/hr based on the lower heating value of the fuel, and that commenced construction, modification, or reconstruction after October 3, 1977. Following the performance test, turbines are required to meet an emission standard for NOx and sulfur dioxide. For NOx, turbines rated at certain capacities or located at certain industries are required to comply with specific provisions of the rule. The rule limits fuel gas sulfur dioxide content to less than 0.015% by volume at 15% oxygen on a dry basis and total sulfur content to less than 0.8% by weight. Based on the date of construction, reconstruction, or modification commenced, the turbine must follow certain monitoring requirements and use a continuous emissions monitoring system (CEMS) in accordance with the rule. The rule also specifies certain test methods and procedures for determining compliance.
8. **Equipment Leaks of VOC From Onshore Natural Gas Processing Plants (NSPS KKK):** A compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by this subpart if it is located at an onshore natural gas processing plant, including each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service. Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0% by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. A leak is detected if an instrument reading of 10,000 ppm or greater is measured. When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected and a first attempt at repair shall be made no later than 5 calendar days after each leak is detected. Pumps in light liquid service, valves in vapor and light liquid service, and pressure relief devices in vapor service that are located at a non fractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements. Reciprocating compressors in wet gas service are exempt from the compressor control requirements, and flares used to comply with this subpart shall comply with the requirements of 40 CFR §60.18.

9. **Onshore Natural Gas Processing SO₂ Emissions (NSPS LLL):** Subpart LLL establishes standards for sulfur dioxide (SO₂) emissions from onshore natural gas processing. The rule applies to sites that process natural gas, including each sweetening unit and each sweetening unit followed by a sulfur recovery unit, and commenced construction or modification after January 20, 1984. Sites with a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide are only required to maintain an analysis demonstrating the design capacity for the life time of the site does not exceed 2 LT/D. For affected sites, the rule requires a SO₂ emission reduction efficiency based on the sulfur feed rate and sulfur content of the acid gas. In addition, the rule requires specific compliance provisions, test methods and procedures, recordkeeping and reporting requirements. Sites that completely reinject acid gas into oil-or-gas-bearing geologic strata or that is not released to the atmosphere are not required to comply with the subpart.

10. **Stationary spark ignition (SI) internal combustion engines (ICE) (NSPS JJJJ):** Subpart JJJJ establishes performance standards for stationary SI ICE. These performance standards are applicable to engines manufactured, modified, or reconstructed after June 12, 2006. For SI ICE engines, NOₓ, CO and VOC emission limits vary and depend on several criteria: the horsepower of the engine (ranging from 25 hp to 1350 hp), rich or lean burn, date of manufacture, and modification or reconstruction commencement date.
11. **Standards of Performance for Stationary Combustion Turbines**: (NSPS KKKK) establishes NOₓ and SO₂ emission limits for stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining the peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners. The following operations are exempt from these standards of performance: emergency combustion turbines, as defined in §60.4420(i), are exempt from the NOₓ emission limits in 40 CFR §60.4320; stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NOₓ emission limits in 40 CFR §60.4320 on a case-by-case basis as determined by the EPA Administrator; stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to 40 CFR Part 60, Subpart Da are exempt from NSPS KKKK; and combustion turbine test cells/stands are exempt from NSPS KKKK.

12. **National Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (MACT YYYY)**: New or reconstructed turbines may have to comply with 40 CFR Part 63 Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. Through a stay of part of the rules issued by the EPA, lean premix and diffusion flame gas-fired stationary combustion turbines are not subject to a majority of the MACT at this time. The only requirement is an initial notification for these units which will be satisfied by the registration of the proposed PBR or standard permit. Since gas-fired turbines are the only units allowed under the PBR and standard permit, there are currently no emission limitations or operating requirements applicable to the units. If the stay is lifted and the units become subject to the rule, oxidation catalysts may be required on the turbines.

13. **Compliance Assurance Monitoring and Periodic Monitoring**: Compliance assurance monitoring (CAM) is a federal monitoring program implemented under the authority of 30 TAC Chapter 122, (Federal Operating Permits), Subchapter G to establish minimal monitoring requirements for state and federal rules for emission units (emission units as defined in Chapter 122) that lack sufficient monitoring, testing, and recordkeeping requirements to demonstrate compliance with emission limitations or standards. Since OGS authorized under PBR Level 2 and standard permit can also be applicable to the federal operating permit program, CAM must be considered.

Periodic monitoring (PM) is a federal monitoring program implemented under the authority of 30 TAC Chapter 122, Subchapter G and applies to emission units at sites with emission limitations or standards. An emission unit requires PM if the emission limitation or standard that the unit is subject to does not specify PM (which may consist of recordkeeping) that is sufficient to yield reliable data from a relevant time period that is representative of the emission unit’s compliance with the applicable requirement and testing, monitoring, reporting, or recordkeeping sufficient to assure compliance with the applicable requirement. Since OGS authorized under standard
permit can also be applicable to the federal operating permit program, PM must be considered.

CAM and PM requirements were not added to proposed 30 TAC §106.352 and the proposed oil and gas standard permit, as CAM and PM requirements are already specified and allowable PM pre-approved options (that is, not case-by-case review of CAM and PM) are already provided in the current oil and gas GOPs. Renewal of the oil and gas GOPs is pending and needs to be completed on or before October 19, 2011. The renewed oil and gas GOPs will have updated CAM and PM requirements and pre-approved options. Sites must be authorized under only PBRs and/or standard permits to qualify for GOPs. Please note that case-by-case review, including case-by-case review of CAM and PM, is not allowed under GOPs.

VII. PROTECTIVENESS REVIEW

An OGS will process gases and liquids associated with the production, conditioning, processing, and pipeline transfer of OGS fluids and gases. OGS use a variety of process equipment which can be arranged in an almost infinite number of possible configurations. Depending on the region in Texas, the composition of the gas or liquids varies greatly. In some areas of Texas, \( \text{H}_2\text{S} \) is required to be extracted from the process stream. These various regions have sour sites that may have significant \( \text{H}_2\text{S} \) and \( \text{SO}_2 \) emissions. Because of these various types operations, equipment, configurations, and composition it was difficult to develop emission limits for each process type or equipment used in a PBR and standard permit that were more comprehensive and demonstrate protectiveness for authorization of the common OGS in Texas. The protectiveness evaluation is even more important when an OGS is located in close proximity to the general public. Therefore, the executive director staff proposed modeling OGS emissions as a unitized maximum concentration based on stack height and the distance from the stack to the nearest off property receptor or property line as a function of each compound’s Effects Screening Level (ESL) or equivalent regulatory limit.

A. Effects Screening Levels

The ESLs are guideline concentrations derived by the executive director’s Toxicology Division and used to evaluate ambient air concentrations of constituents. ESLs are based on data concerning health effects, the potential for odors to be a nuisance, effects on vegetation, and corrosive effects. They are not ambient air standards. If predicted or measured airborne levels of a constituent do not exceed the screening level, adverse health or welfare effects are not expected. If ambient levels of constituents in air exceed the screening levels, it does not necessarily indicate a problem but rather triggers a more in-depth review, which is the purpose of the case-by-case permitting process. The current ESL list is available through: [http://www.tceq.state.tx.us/assets/public/implementation/tox/esl/list/october2009.pdf](http://www.tceq.state.tx.us/assets/public/implementation/tox/esl/list/october2009.pdf).

Current hourly and annual ESLs which are likely to be applicable to OGS from both production and MSS activities include the following common compounds and are summarized in the Effects Screening Level table below. Emissions for treatment chemicals (including but not limited to, amines, glycols, and methanol) may need to be evaluated if used in sufficient quantities. These chemicals’ ESLs vary, so the current list should be referenced for specific information.
VOC sampling data from the Air Quality Research project HO51C, *Evaluation of VOC Emissions from Flash and Condensate Tanks*, and other industry supplied information was reviewed by the Toxicology Division, and ESLs were developed for common mixtures of chemicals at OGS: natural gas, crude oil and condensate. The ESL developed by the Toxicology Division for condensate has recently been updated to 3,500 µg/m$^3$. The Toxicology Division had previously developed ESLs for crude oil at 3,500 µg/m$^3$, and natural gas at 18,000 µg/m$^3$.

The short-term ESLs for crude oil and condensate (3,500 µg/m$^3$) were set based on the weight percent of components in typical crude oil (raw data available upon request). The ESLs were developed by calculated by each component’s weight percent and its respective ESL using a formula for the derivation of a chemical product. Accordingly, an ESL of the chemical product can be derived by the following formula where $f_n$ equals the fractional quantity of component ‘n’ in product X, and ESL$_n$ equals the ESL for component ‘n’:

$$X = \frac{1}{f_a / ESL_a + f_b / ESL_b + f_c / ESL_c + \ldots + f_n / ESL_n}$$

The Formaldehyde ESL was posted on the commission’s website on August 2008 and is available through [www.tceq.state.tx.us/implementation/tox/dsd/final.html](http://www.tceq.state.tx.us/implementation/tox/dsd/final.html).

The annual ESL for benzene is substantially lower than any of the corresponding ESLs for other air contaminants expected to be emitted at an OGS. To analyze the annual acceptable emissions of benzene, both the hourly and annual impacts must be evaluated for protectiveness. Additional information on the development supporting document for benzene is available through: [www.tceq.com/assets/public/implementation/tox/dsd/final/benzene_71-43-2_final_10-15-07.pdf](http://www.tceq.com/assets/public/implementation/tox/dsd/final/benzene_71-43-2_final_10-15-07.pdf).

**B. Groups of Similar Releases**

Based on the variability of equipment and operations, it was determined that emission releases would be grouped for dispersion modeling to predict acceptable off-property impacts. This analysis was compared to expected emission types and quantities for

<table>
<thead>
<tr>
<th>Substance</th>
<th>Hourly Concentration (µg/m$^3$)</th>
<th>Annual Concentration (µg/m$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil</td>
<td>3,500</td>
<td>350</td>
</tr>
<tr>
<td>Condensate</td>
<td>3,500</td>
<td>350</td>
</tr>
<tr>
<td>Natural gas</td>
<td>18,000</td>
<td>1,800</td>
</tr>
<tr>
<td>Benzene</td>
<td>170</td>
<td>4.5</td>
</tr>
<tr>
<td>Toluene</td>
<td>640</td>
<td>1,200</td>
</tr>
<tr>
<td>Ethylbenzene</td>
<td>2,000</td>
<td>200</td>
</tr>
<tr>
<td>Xylene</td>
<td>350</td>
<td>180</td>
</tr>
<tr>
<td>Formaldehyde</td>
<td>15</td>
<td>3.3</td>
</tr>
<tr>
<td>Cyclohexane</td>
<td>420</td>
<td>42</td>
</tr>
<tr>
<td>Methylcyclohexane</td>
<td>4,000</td>
<td>400</td>
</tr>
</tbody>
</table>
assessment of protectiveness and compliance with state and federal emission standards from common OGS. The “generic” approach could also be used to show the appropriate insignificance or acceptability of various operations, providing additional flexibility for OGS seeking authorization under the PBR or standard permit. The groups of similar emission releases were chosen based on similar parameters of the release points. The executive director staff’s analysis identified four distinct groups: process unit vents and similar stacks, fugitive components, tanks, and loading of trucks; blowdowns and similar MSS activities; combustion units; and thermal destruction devices (flares).

To ensure a representative, reasonable, worst-case set of dispersion parameters to evaluate, the executive director’s staff researched permit files. One of the steps in identifying and modeling a set of conservative sources was to generate a list of OGS authorized by the current standard permit with large emissions. The Air Permits Division document and data management systems were initially searched, but no consistent results could be found to develop a firm list of sources with larger emissions. Instead, the executive director staff reviewed the agency’s air emission inventory from 2004 based on SIC code and authorization type. The list was separated and sorted (highest to lowest) for: NOx, VOC, H2S, and SO2 emission quantities. High emission value sites were researched and the standard permits identified at a dozen or more sites on the high end of the list. Many of the facilities at these OGS were used to confirm appropriate dispersion parameters and, subsequently, confirm if these types of OGS could meet the proposed PBR and standard permit conditions.

C. Modeling Procedures and Impacts Analysis

The impacts analysis considered numerous variables including: emission source types and associated emission parameters; building wake effects (downwash); meteorological data; receptor grid, and model use and techniques. Generic modeling was conducted to account for sources at all oil and gas production sites. Tables were created from concentrations predicted by the Industrial Source Complex Short Term 3 (ISCST3) (Version 02035) model. The ISCST3 model is based on the Gaussian distribution equation and is inherently conservative due to the main simplifying assumptions made in its derivation: conditions are steady-state (for each hour, emissions, wind speed and direction are constant) and the dispersion from source to receptor is effectively instantaneous; there is no plume history as model calculations in each hour are independent of those in other hours; mass is conserved (no removal due to interaction with terrain, deposition, or chemical transformation) and is reflected at the surface; and, plume spread from the centerline follows a normal Gaussian distribution and only vertical and crosswind dispersion occurs, dispersion downwind is ignored. In addition, the model provides conservative results for short distances and low-level emissions and tends to over-predict ground-level concentrations. The model was applied in a screening mode to ensure predictions were conservative (higher predicted concentrations) for this application. The rural dispersion option was used as it would be rare for oil and gas facility plumes to be influenced by urban dispersion effects. All emissions sources were co-located on a single site, in order to minimize bias due to source configuration and wind direction. This technique also provides conservative results since the cumulative impact from all sources is maximized.

Fugitive emissions evaluated included emissions associated with storage tanks, process equipment, and truck loading. Point source emissions evaluated considered vent emissions for six different stack heights, combustion units (reciprocating engines) for 11 different
stack heights, thermal destruction devices (flares) for five different stack heights, and gas compressor and gas pipeline blowdown emissions for three different stack heights. A detailed description of the emissions inventory follows. Each source was modeled separately at a unitized emission rate of one pound per hour. This technique determined a unitized maximum predicted ground-level concentration (GLCmax) for each source. The GLCmax for each source or source group can then be divided into the ESL or standard for each contaminant to determine the allowable emission rate for each contaminant.

Process vents, fugitives, tanks, and loading were based on a large group of data. Well over 100 control and process units were reviewed by the executive director staff for vent emission parameters in early 2005. In 2007, an additional number of standard permit and PBR files were reviewed. Since impacts are dependent on emission rate, height of release and temperature, it was evident that uncontrolled low-height, low-temperature process vent sources would have the most impact at any nearby receptor. A representative, random sample of seven complex sites were reviewed, resulting in 21 facilities with detailed temperature, process rate of gas or oil, type of unit, vent diameter and vent height of discharge, and exit velocities were available. These sites had gas processing rates up to approximately 215 million dry cubic feet (MMCFD) and liquid production rates up to approximately 8,000 barrels per year. Of the 21 facilities reviewed, stack heights ranged from 12 to 39 feet, diameters from 0.05 to 3.5 feet, exit velocity from 1 to 90 ft/sec, and temperatures from 80 °F to 800 °F. The range of parameters modeled for process vents were release heights from 10 to 60 feet in increments of 10 feet. A vent diameter of one foot at 500 acfm at 120°F with a velocity of 10.6 ft/sec was selected as the reasonable worst-case parameters for air dispersion modeling.

The process vent stack sources are representative of stacks and vents not associated with truck loading or storage tanks, such as amine treaters and glycol dehydration units. Stack parameters were derived from a review of permitted sources. These sources were represented as point sources. The results of the impact analysis are summarized in Table 2.

Fugitive sources comprise all fugitive emissions from a representative oil and gas site. Fugitives were represented as three sources. Fugitive emissions were represented as three sources: a circular area source with a 3 feet release height and 30 feet diameter; a point source with a 3 meter release height; and a point source with a 6 meter release height. Low level fugitive emissions occur at various locations within a plant site. Since the resulting emissions are usually well distributed throughout a site, an area source representation is appropriate. The circular area source type was selected to minimize bias of any one wind direction or source orientation. The loading and tank fugitives’ emissions do not release to the atmosphere through standard stacks and generally are not distributed throughout a site. The loading and tank fugitive emissions are represented by the point source characterization co-located with the circular area source using pseudo-point source parameters.

Combustion unit emission sources are represented as the stacks associated with reciprocating engines. Representative worst-case stack parameters were derived from an industry review of permitted sources. For engines at or below 1,000 hp, 100% load at a stack flow rate of 4,800 acfm at 900 °F was used in the analysis. For engines greater than 1,000 hp, 75% load at a stack flow rate of 9,500 acfm at 900°F was used in the analysis. A stack diameter of 10 inches was modeled with an exit velocity of 159 ft/sec and 315 ft/sec, respectively. Engine exhaust stacks were modeled as point sources with release heights of 8, 10, 12, 14, 16, 18, 20, 25, 30, 35, and 40 feet. The ambient ratio factor of 0.75 was used in
the protectiveness analysis to represent the conversion of NO\textsubscript{x} to NO\textsubscript{2}.

Heaters, boilers, and similar process units should use Table 2, and not those developed for engines and turbines as the flow data showed these units have releases well below the values used in this analysis. In addition to process vents, OGS commonly have one or more combustion units, often internal combustion engines used to operate compressors. Since the dispersion characteristics of these units have higher flow, some amount of thermal buoyancy, and same or similar release heights to process vents, these factors combine to have greater dispersion, and thus higher emissions would be allowable. Engines and turbines should use Tables 3 and 4. Turbines were not separately analyzed because of limited registrations involving turbines. Since engines have worse dispersion characteristics than turbines, Table 4 is appropriate for turbines.

Numerous files were evaluated for thermal destruction devices, including thermal oxidizers, boilers, heaters, flares, and fire box incinerators. The most common facilities found were flares. Flares continuously burn a pilot flame, resulting in small amounts of NO\textsubscript{x}, CO, SO\textsubscript{2}, and PM\textsubscript{10} being emitted. When a process stream is being destroyed, slightly higher amounts of these pollutants are released. In addition, when flares are being used to destroy process waste streams or during planned MSS, some amount of VOCs are released, which may contribute to off-property impacts. More importantly, when a flare is used at a sour site, sulfur compounds (primarily H\textsubscript{2}S) converts to SO\textsubscript{2}, and, depending on the waste streams, may potentially emit significant amounts of this criteria air contaminant.

These sources are representative of all processes associated with flares and other thermal destruction devices. Representative worst-case stack parameters were derived from a review of industry thermal control devices. The most common facility found was a flare. Emission rates and stack parameter data were gathered for approximately 20 sites. The assumptions used in developing the worst-case parameters were a minimum energy value of 200 British thermal unit per standard cubic foot (btu/scf) in accordance with NSPS in 40 CFR §60.18, and a minimum height of 20 feet. Five sites of those reviewed had low flow values ranging from 691 to 3,129 standard cubic feet per minute (scfh). These were averaged to derive a reasonable low flow value of 2,400 scfh. Flares were modeled as point sources with temperature of 1273 Kelvin (K) (1832 °F), exit velocity of 20 meters/sec (66 ft/sec), release heights of 20, 30, 40, 50, and 60 feet, and a diameter of 6 inches. The values for the exit temperature and velocity are default values for modeling flares. Many sites have flares or similarly designed thermal destruction devices to control VOCs during production and planned MSS. Since the dispersion characteristics of these units have higher or lower flow, thermal buoyancy, and usually higher release heights to process vents, these factors combine to have greater dispersion, and thus higher emissions would be allowable.

Blowdowns and similar MSS activities were also reviewed. Compressor blowdowns allow emissions to be released through a stack when an OGS temporarily vents a gas compressor. Similarly, pipeline releases are for the temporary venting of a gas pipeline. Compressor blowdown stack sources are representative stacks used for the temporary venting of a gas compressor. Stack parameters were derived from a review of industry sources. Three sites with the highest planned MSS emissions of the sites reviewed were selected in order to derive representative worst-case modeling parameters for compressor blowdowns. A stack flow rate of 100 acfm at ambient temperature was used in the model. A stack diameter of 6 inches was modeled with an exit velocity of 8.5 ft/sec. The stack heights modeled ranged from 3 feet to 20 feet. Pipeline blowdown stack sources are representative stacks used for
the temporary venting of a gas pipeline. Stack parameters were derived from a review of industry sources. Three sites with the highest planned MSS emissions of the sites reviewed were selected in order to derive representative worst-case modeling parameters for pipeline blowdowns. A stack flow rate of 2,400 acfm at ambient temperature was used in the model.

A stack diameter of 6 feet was modeled with an exit velocity of 1.4 ft/sec. The stack heights modeled ranged from 3 feet to 20 feet.

The modeling analysis used a polar receptor grid with 36 radials spaced every 10 degrees from true north. Receptors were located on each radial at distances of 50, 100, 150, 200, and every one hundred feet out to 3,000 feet. To streamline the modeling analysis, surface meteorological data from Austin and upper-air data from Victoria for the years 1983, 1984, 1986, 1987, and 1988 was used. Since the allowable emission rates in the tables are based on maximum hourly emission rates, this five-year data set would include worst-case meteorological conditions that could occur anywhere in the state. In addition, the wind directions were set at 10 degree intervals to be coincident with the receptor radials. This approach ensures the highest predictions as the plume centerline passes directly over each receptor which is a conservative result.

Based on a review of existing sites, no downwash structures were included in the analysis. No significant structures would likely exist at these types of sites that would influence dispersion. In addition, downwash is not applicable to area sources.

The modeling analysis document can be found through the Air Permits Remote Document Server, in the New Source Review General (NSRG) library under document number 9880 and 10434. The modeling files can be found in the NSRG library under document number 9881 and 10435. The result of this analysis was used to develop tables for confirmation of acceptable emissions for any applicable standards and ESLs. These tables are included in the proposed PBR as one of three possible tools available to the regulated community to demonstrate protectiveness.

### D. How to use Modeling Results

To use the modeling tables, a corresponding lb/hr maximum emission rate can be determined using the following equations. This equation is similar to that currently identified in §106.262 (\( E = \frac{L}{K} \)), but with different parameters.

For an ambient air standard: \( E_{\text{max}} = \frac{P}{G} \) where \( E_{\text{max}} \) is the maximum hourly emissions acceptable (lb/hr); \( P \) is the appropriate property line standard (µg/m³); and \( G \) is the value from the Generic Emissions Tables at the emission point’s release height and distance to property line (µg/m³)/(lb/hr).

For health effects review: \( E_{\text{max}} = \frac{ESL}{G} \) where \( E_{\text{max}} \) is the maximum acceptable hourly emissions (lb/hr); ESL is the current published effects screening level for the specific air contaminant (µg/m³); and \( G \) is the value from the Generic Emissions Tables at the emission point’s release height and distance to property line (µg/m³)/(lb/hr).

Most OGS have more than one facility or release point of emissions. To account for this variability, instead of co-locating all sources at the most conservative point of release to establish acceptable emission rates and confirm compliance with the proposed PBR or
standard permit, OGS may use a weighted fraction method. The four tables predict impacts based on various dispersion characteristics, with greater acceptable emissions from various sources (smallest to largest): fugitives, blowdowns, process vents, combustion devices, and flares. Since many of these facilities emit air contaminants simultaneously, the corresponding contribution of each release must be considered to ensure acceptable emissions. Therefore, acceptable emission limits are determined using a weighed ratio. For simultaneously emitting sources, the weighted fraction method with the above equation may be used for any combination of sources emitting the same air contaminant:

\[
E_{\text{max}} (\text{lb/hr}) = (\text{WR EPN 1}) \left( \frac{P}{G} \text{ EPN 1} \right) + (\text{WR EPN 2}) \left( \frac{P}{G} \text{ EPN 2} \right) + (\text{WR EPN 3}) \left( \frac{P}{G} \text{ EPN 3} \right) + \ldots
\]

or

\[
E_{\text{max}} (\text{lb/hr}) = (\text{WR EPN 1}) \left( \frac{\text{ESL}}{G} \text{ EPN 1} \right) + (\text{WR EPN 2}) \left( \frac{\text{ESL}}{G} \text{ EPN 2} \right) + (\text{WR EPN 3}) \left( \frac{\text{ESL}}{G} \text{ EPN 3} \right) + \ldots
\]

With minor adjustments, this same equation can be used for annual impacts evaluation. Standard practice, as those published in the TCEQ Modeling Guidance Document which may be found at http://www.tceq.state.tx.us/permitting/air/guidance/newssourcereview/nsr_mod_guidance.html, is to multiply the hourly impact concentration by 0.08 to establish a conservative annual impact concentration. Thus, the weighted fraction equations would be:

\[
E_{\text{max}} (\text{tpy}) = \left( \frac{8760}{2000} \right) \{ (\text{WR EPN 1}) \left( \frac{P}{0.08 \times G \text{ EPN 1}} \right) + (\text{WR EPN 2}) \left( \frac{P}{0.08 \times G \text{ EPN 2}} \right) + (\text{WR EPN 3}) \left( \frac{P}{0.08 \times G \text{ EPN 3}} \right) + \ldots \}
\]

or

\[
E_{\text{max}} (\text{tpy}) = \left( \frac{8760}{2000} \right) \{ (\text{WR EPN 1}) \left( \frac{\text{ESL}}{0.08 \times G \text{ EPN 1}} \right) + (\text{WR EPN 2}) \left( \frac{\text{ESL}}{0.08 \times G \text{ EPN 2}} \right) + \ldots \}
\]

where

- \( E_{\text{max}} (\text{lb/hr}) \) = maximum hourly emissions acceptable (lb/hr)
- \( E_{\text{max}} (\text{tpy}) \) = maximum tons per year emissions acceptable (tpy)
- \( \text{WR EPN(x)} \) = emissions of each EPN divided by the sum of total emissions for all EPNs that emit that pollutant or \( (E_{\text{EPN}} / E_{\text{total}}) \)
- \( P = \) short term or annual (as appropriate) property line standard (µg/m³)
- \( \text{ESL} = \) current published short term or annual (as appropriate) effects screening level for the specific air contaminant (µg/m³)
- \( G = \) value from the Generic Emissions Tables at the emission point’s release height and distance to property line (µg/m³/[lb/hr])

The cumulative impacts from any given OGS must be considered for protectiveness. To provide flexibility, applicants may use the weight fraction method of proportioning impacts in the same way as PBR §§106.261 and 106.262 currently use to proportion impacts from different sources at different distances. The proposed authorizations will contain several tables applicable to the type sources located at the site. This will enable an applicant to compute their emission limits for the applicable air contaminants from those sources. Each table will allow an applicant to either meet specific emission limits, or compute the specific emission limit for that type source. These tables can be used assuming 100% of the specific emissions are at a worst-case point (very conservative). They may also be used to compute the specific emission limit for each emission point (may involve different distances, heights, and type tables) by use of the weight fraction method, which will allow for consideration of multiple, similarly emitting sources operating simultaneously at an OGS. The most conservative approach using the worst-case source calculated from each table will result in the maximum impact allowed for protectiveness from that source without regard to other sources emitting the same compound at the same time. Using the weight fraction approach,
emission limits can be established for all other type equipment emitting the same compound at the same time. If the OGSs estimated emission rates using either method are less than or equal to the calculated emission rate limit as determined from the tables, the emission are acceptable and can be authorized.

Occasionally, compressed gases from a compressor station or pipeline have to be purged for planned MSS activities, referred to as a blowdown. Emissions from blowdowns do not occur at the same time as regular production emission based on the representations in permit reviews. Therefore, these different operating scenarios can have different limits. In no cases should any values be generated for distances (less than 50 feet or greater than 5,500 feet) or stack heights beyond the boundaries established by a particular table.

E. Summary of Modeling Results

Various OGS activities were examined for their potential effect on public health, and the executive director staff concluded that as long as site-wide emission caps for each pollutant are not exceeded, the restrictions imposed by the proposed PBR and standard permit are protective of public health. No “exceedances” of an ESL are expected for qualifying sites. A complete report of modeling results is available by request to the executive director.

Based on the file evaluation of previously represented emission rates from various facilities at OGS and the tables generated, the quantity of certain criteria pollutants (CO & PM$_{10}$), consistently meets all federal national ambient air quality standards. While NOx now has both hourly and annual NAAQS, based on several examples, it appears the hourly impacts will be the limiting factor (assuming sources at an OGS operate continuously except for planned MSS). In addition, numerous speciated VOCs (BTEX, propane, butane, and others) were evaluated from both files and hypothetical cases based on concentration percentage and relative ESL. In almost every instance, the compound benzene triggered limits before any other VOC compound.

Therefore, while all records, certifications, and registrations will require emission limit calculations, certain air contaminants will not be required to confirm compliance with the impact tables. Based on the review, there are specific air contaminants with state or federal standards that must show how the emissions will meet standards, especially H$_2$S and SO$_2$ and NOx. Certain speciated VOC air contaminants emitted from an OGS also must be evaluated against the impact tables or other methods. The air contaminants common and needing to be confirmed for acceptability are benzene, toluene, and xylene.

F. Impacts Analysis of Air Contaminants

Based on the tables developed for site-wide OGS analysis, there is a large range of possible emissions which would be allowable and protective of public health and welfare. The executive director staff also reviewed these possible values, and combinations of limits, against a random sample of PBR and standard permit registrations over the last 4 years. In general, the emissions from registrations have been within the limits proposed, or with the installation of a vapor recovery system, could meet the proposed limits.

To demonstrate the maximum acceptable emissions at various locations from various sources, the commission has included as an appendix with emission charts completed for the pollutants of interest at OGS. These charts are not intended for direct inclusion in the
To determine when emissions from certain air contaminants need to be specifically included in a protectiveness demonstration, the commission used the proposed generic tables to estimate the maximum acceptable hourly emissions that would not exceed any ambient standard or ESL. In addition, to determine whether typical OGS in Texas would meet the predicted emission limits, the commission reviewed hundreds of OGS PBR and standard permit registrations and reports and set reasonable emission rates and site-wide caps based on the conservative predictions from the entire receptor grid of the impacts analysis. The following summarizes the results of the commission’s review:

Carbon monoxide has a 1-hour ambient air standard of 40,000 μg/m³ and an 8-hour standard of 10,000 μg/m³, as measured at the nearest property line to the authorized facilities. The most substantial sources of CO at OGS are from engines. Using a conservative impacts evaluation for engines, at the shortest distance (50 feet) and the lowest dispersing stack (8 feet), the maximum predicted acceptable amount of emissions from engines greater than 1,000 hp (the highest quantity source of CO at an OGS) would be 3,070 pounds per hour (lb/hr) and 1,509 lb/hr for engines less than 1,000 hp. After a random audit of approximately a hundred reviewed OGS PBR registrations in 2010, the range of CO emissions for sites was represented to be from 0.03 lb/hr to 14 lb/hr, with an average of 4 lb/hr. Based on this information, it is extremely unlikely that any OGS will have or contribute to an exceedance of the CO 1-hour or 8-hour NAAQS.

Particulate matter less than 10 microns and particulate matter less than or equal to 2.5 microns (PM_{10}, PM_{2.5}) have 24-hour ambient air standards of 150 μg/m³ and 35 μg/m³, respectively. Additionally, the annual ambient air standard for PM_{2.5} is 15 μg/m³. For the purposes of this analysis and review, it is assumed that all PM_{10} consists of PM_{2.5}, which is the more stringent of the two standards. The most quantifiable source of PM emissions at OGS is as products of combustion from mainly engines or other combustion producing sources. Using the conservative impacts evaluation tables at the shortest distance (50 feet) and lowest dispersing stack (8 feet), the maximum predicted acceptable amount of emissions from engines would be 6.3 lb/hr for PM_{10} and 1.5 lb/hr for PM_{2.5}. Based on these same tables, annual emissions could potentially be limited to 210 tpy and 63 tpy for PM_{10} and PM_{2.5}, respectively. After a random audit of approximately a hundred reviewed OGS PBR registrations in 2010, the range of PM_{10} emissions for sites was represented to be 0.01 lb/hr to 0.67 lb/hr, with an average of 0.08 lb/hr. The range of PM_{10} annual emissions for sites were represented to be 0.01 tpy to 0.57 tpy. Based on this information, it is extremely unlikely that any OGS will have or contribute to an exceedance of any PM_{10} or PM_{2.5} NAAQS.

Sulfur dioxide has several state ambient air standards, depending on location and time frame. The most stringent is a 30-minute state standard for Harris and Galveston counties of 715 μg/m³. The EPA has finalized a new hourly NAAQS of 196 μg/m³ (based on the EPA announcement June 3, 2010). The most quantifiable sources of SO₂ at OGS are from flares or other waste stream thermal control devices, mostly from burning sour waste streams. Using a conservative impacts evaluation for flares at the shortest distance (50 ft), lowest dispersing stack height (20 ft), and the new proposed NAAQS (196 μg/m³), the acceptable
amount of emissions would be 3.4 lb/hr. At approximately 1/4 mile (1,400 feet) from the source, acceptable emissions could be 5.4 lb/hr and at 1/2 mile (3,000 feet) could be over 9.8 lb/hr. Based on a random audit of approximately one hundred reviewed OGS PBR registrations in 2010, the range of SO₂ emissions for sour sites was represented to be 35 lb/hr to 40 lb/hr, with an average of 37 lb/hr. In the same audit, the range of SO₂ emissions for sweet sites was represented to be 0.01 lb/hr to 6.30 lb/hr, with an average of 4.25 lb/hr.

Although the typically highest quantity of SO₂ occurs from flares, there are other releases of SO₂ at OGS. Any stream going to the amine reboiler will be an extremely concentrated sour gas stream and emissions from this process vent may be substantial. The dispersion characteristics of this process vent result in lower acceptable emissions as compared to a flare. Based on the impacts table for process vents at 10 feet, the smallest amount of SO₂ which meets the NAAQS at 50 feet is 0.4 lb/hr. Based on this information the commission would not expect a demonstration of impacts for any source to be needed at less than 0.4 lb/hr.

Hydrogen sulfide has several state ambient air standards, depending on location. The most stringent is a 30-minute standard of 108 μg/m³. There are many quantifiable sources of H₂S at OGS, including fugitives, tank hatches, loading, blowdowns, and flares or other waste stream thermal control devices. Using a conservative impacts evaluation for fugitives and vents, at the shortest distance (50 ft) and lowest dispersing stack height (3 ft), the acceptable amount of emissions would be 0.03 lb/hr. At approximately 1,400 feet from the source, acceptable emissions could be 0.5 lb/hr (10 ft stack - loading dispersion) and at 3,000 feet could be 2 lb/hr (3 ft stack). Based on a random audit of approximately a hundred of reviewed OGS PBR registrations in 2010, the range of H₂S emissions from both sweet and sour OGS was represented to be 0.01 lb/hr to 0.62 lb/hr, with an average of 0.07 lb/hr. Based on this information, the commission would not expect demonstration of impacts for sources at less than 0.03 lb/hr.

Nitrogen oxides are used to evaluate the NO₂ ambient 1-hour air standard of 188 μg/m³ and an annual ambient air standard of 100 μg/m³ as measured at the nearest property line to the authorized facilities. The most substantial sources of NOₓ at OGS are engines. Using a conservative impacts evaluation for engines, the ambient ratio factor of 75% of NOₓ is NO₂, at the shortest distance (50 ft) and lowest dispersing stack height (8 ft), the acceptable amount of emissions from engines greater than 1,000 hp would be 19 lb/hr. Additionally, for engines less than 1,000 hp acceptable emissions from engines would be 9 lb/hr. For engines greater than 1,000 hp, at approximately 1,400 feet from the source, acceptable emissions could be 29 lb/hr and at 3,000 feet could be over 35 lb/hr. Additionally, for engines less than 1,000 hp, at approximately 1,400 feet from the source, acceptable emissions could be 15 lb/hr and at 3,000 feet could be over 21 lb/hr. Based on a random audit of approximately a hundred reviewed OGS PBR registrations in 2010, the range of NOₓ emissions for sites was represented to be 0.36 lb/hr to 19 lb/hr, with an average of 4 lb/hr. Based on this information the commission would not expect demonstration of impacts for any engine or combustion source to be needed at less than 9 lb/hr. Based on actual registration information it is anticipated that most, if not all, engines should meet the hourly and annual NO₂ NAAQS.

Compliance with ESLs were also evaluated for possible inclusion as a requirement of proposed OGS PBR registrations. The maximum concentration of various speciated or groups of speciated VOCs were reviewed, including: natural gas (hourly 18,000 μg/m³), crude oil (hourly 3,500 μg/m³), condensate (hourly 3,500 μg/m³), benzene (hourly 170
μg/m³ and annual 4.5 μg/m³), toluene (640 μg/m³), xylene (350 μg/m³), other typical chemicals found in petroleum streams, and formaldehyde (hourly 15 μg/m³) which is generated as a result of operating internal combustion engines. There are many quantifiable sources of VOCs at OGS, including fugitives, tank hatches, loading, flares or other waste steam thermal control devices, and blowdowns during planned MSS activities.

Forty-four OGS standard permit registrations were evaluated. The commission determined the following chemicals need to be speciated for impacts evaluation for both speciated and total VOC emissions. The determination of specific constituents which need to be reviewed was based on actual emissions, variability of actual emissions, lowest, highest, and average weight percents of each constituent, and contribution of each speciated constituent based on weight percents and ESLs. The following 14 speciated constituents were addressed: benzene, butanes, cyclohexane, decane, ethylbenzene, heptane, methlycyclohexane, n-hexane, nonanes, octanes, pentanes, propane, toluene, and xylene. These 14 were chosen because they were the only speciated constituents with more than four data points (10%) from the 44 registrations. The chemicals which showed the highest potential culpability for impacts were: benzene, toluene, xylene, ethylbenzene, cyclohexane, and methlycyclohexane.

Ethylbenzene, cyclohexane, and methlycyclohexane were further evaluated and determined to not be constituents that drive the need for an impacts review. The commission determined that the conservative modeling results for these constituents resulted in values which were higher than the actual emissions represented in the 44 registrations. Additionally, comparing the conservative modeling to the actual concentrations, the commission has seen from monitoring emissions of ethylbenzene, cyclohexane, and methlycyclohexane are not expected to cause an exceedance of ESLs. One of a total of 22 data points had represented actual emissions for ethylbenzene which was above the 0.457 lb/hr allowable emissions for ethylbenzene at 50 feet for fugitive releases; 21 of 22 had represented emissions that were less than 10% of 0.457 lb/hr. Three out of 14 data points had represented actual emissions for cyclohexane which were above the 0.32 lb/hr allowable emissions for cyclohexane at 50 feet for fugitive releases; 11 out 14 had represented actual emissions which were less than 50% of 0.32 lb/hr. Seven out of seven data points for methlycyclohexane had represented emissions which were below the 0.80 lb/hr allowable emissions for methlycyclohexane at 50 feet for fugitive releases.

Due to the magnitude of some of the actual emissions, variability of emissions, and variability of weight percents of xylene and toluene from the 44 registrations, the weighted contributions to impacts for toluene and xylene, in comparison to allowable emissions based on the impacts tables, the commission determined that toluene and xylene need to be speciated for impacts review when a site is less than 2,700 feet from the nearest off-plant receptor. Seven of 33 data points for toluene were greater than the values predicted by the tables at less than 2,700 feet. However, actual represented emissions for 26 of 33 data points were below the allowable emissions of 0.146 lb/hr at 50 feet for toluene fugitives. Based on this evaluation, emissions less than 0.146 lb/hr of toluene do not need an impacts evaluation. However, evaluation for toluene should occur for emissions greater than 0.146 lb/hr for distances to receptors between 50 feet and 2,700 feet. Six of a total of 27 data points for xylene were greater than the values predicted by the tables at less than 1,400 feet. However, actual represented emissions for 21 of 27 data points were below the allowable emissions of 0.08 lb/hr at 50 feet for xylene fugitives.
Benzene was confirmed as the main constituent of VOC for impacts review. Thirty-four data points were obtained for benzene from the 44 registrations. In particular, the average weight percent was three, the high weight percent was 18, and the low weight percent was 0.008. For at least two categories (high and average) the culpability of benzene’s contribution to the impact analysis was the greatest of all constituents evaluated. Benzene has been the focus of commission attention and public concern. Benzene is considered a relatively toxic air contaminant, and erring on the side of caution, the commission has proposed that impacts of benzene must be evaluated for distances to receptors between 50 feet and 2,700 feet. Additionally, 17 out 34 data points were represented below 0.039 lb/hr allowable emissions for fugitive releases at 50 feet, and 20 out of 34 data points were represented at or below 0.04 lb/hr, showing the potential for many sites to have negligible emissions of benzene.

All three air contaminants will need to demonstrate acceptable impacts when distances to receptors are between 50 feet and 2,700 feet, unless they are below the minimum pound per hour established in the rule. Additionally, total hourly and annual allowable emissions of VOCs and benzene and allowable pound per hour emissions of toluene and xylene are established in the proposed rule. Speciated emissions and total VOCs emissions, if not initially based on testing as required, must eventually be updated and based on site-specific testing results. Demonstration of meeting the impacts for benzene, xylene, and toluene is a surrogate for a demonstration for total VOC emission limits proposed for this PBR. The analysis determined that if these three constituents can meet the impacts analysis and are protective, then all remaining VOCs should meet the impacts analysis and be protective because they have the highest combination of greatest weighted concentration and lowest ESLs of all the VOC constituents identified for natural gas, condensate and crude oil.

Formaldehyde has an hourly ambient air standard of 15 μg/m$^3$ and an annual ambient air standard of 3.3 μg/m$^3$. The most quantifiable source of formaldehyde emissions at OGS is from engines. Using the conservative impacts evaluation tables at the shortest distance (50 ft) and lowest dispersing stack height (8 ft), the acceptable amount of emissions from engines greater than 1,000 hp would be 1.15 lb/hr. For engines less than 1,000 hp the acceptable amount of emissions would be 0.57 lb/hr. After a random audit of approximately a hundred reviewed OGS PBR registrations in 2010, the range of formaldehyde emissions for sites was represented to be 0.01 lb/hr to 0.74 lb/hr, with an average of 0.28 lb/hr. Based on this information, the commission would not expect demonstration of impacts for any engine to be needed at less than 0.57 lb/hr.

VIII. ENCOURAGING RECOVERY AND OFFERING INCENTIVES

The TCEQ has numerous programs and information to encourage pollution prevention and recovery, including Clean Texas (www.tceq.state.tx.us/assistance/cleantexas/cleantexas.html) and SAV+ (http://www.tceq.state.tx.us/assistance/P2Recycle/site-visits.html). The EPA also has the Natural Gas STAR program (http://www.epa.gov/gasstar/). In addition to these resources, the TCEQ has established various industry-specific pollution prevention opportunities which include detailed, good-operating practices that help prevent pollution. Pollution Prevention Through Good Operating Practices (Raw Material and Product Storage) includes the following items:

- establishment of Spill Prevention, Control and Countermeasure (SPCC) plans
- use of properly designated tanks and vessels only for the intended purposes
- installation of overflow alarms for all tank and vessels
- maintenance of physical integrity of all tanks and vessels
- installation of leak detection systems in storage tanks
- establishment of written procedures for all loading/unloading and transfer operations; installation secondary containment areas
- instruction of operators to not bypass interlocks, alarms, or specifically alter set points without authorization isolation of equipment or process lines that leak or are not in service; use of seal-less pumps
- use of bellows-seal valves
- use of a gravity spigot or pump to reduce spills when dispensing bulk liquids
- use of a spout and funnel when transferring liquids
- use of drip-catchers; use of dry clean-up methods for spills whenever possible
- documentation of all spillage to establish precautionary measures in the future
- performance of overall materials balances and estimate the quantity and dollar value of all losses
- use of double-seal floating-roof tanks for VOC control; use of conservation vents on fixed roof tanks
- use of vapor recovery (vapor balance) systems
- storage of products in locations/under conditions that will preserve their shelf life
- maintenance of tight fitting lids and bungs on containers (even those that are empty)
- storage of containers in such a way as to allow for visual inspection for corrosion and leaks
- stacking containers in a way to minimize the chance of tipping, puncturing, or breaking
- storage of packages, etc., properly to prevent damage or contamination
- protection of items stored outdoors from temperature extremes, rain, snow, wind, severe weather
- prevention of concrete “sweating” by raising the drum off storage pads (e.g., on pallets)
- maintenance of Material Safety Data Sheets to ensure correct handling of spills
- providing adequate lighting in the storage area; maintenance of a clean, even surface in transportation areas keeping aisles clear of obstructions
- maintenance of distance between incompatible chemicals
- maintenance of distance between different types of chemicals to prevent cross contamination
- avoidance of stacking containers against process equipment
- adherence to manufacturer’s suggestions on handling and use of all materials
- using proper insulation of electrical circuitry and inspecting regularly for corrosion and potential sparking
- using large containers for bulk storage whenever possible
- using containers with height-to-diameter ratio equal to one to minimize wetted area
- emptying drums and containers thoroughly before cleaning or disposal
- reusing and recycling scrap paper

There are numerous company (as well as environmental) benefits from implementing some or all of these ideas, including: reduced fees for select TCEQ training; technical assistance and networking; improvement in Compliance History; single point of contact within TCEQ for innovation activities; reduced state investigation frequency and additional notice on a case-by-case basis; customized recognition such as press releases, news articles, and on-site events; expedited administrative and technical review of state permits on a case-by-case basis; Exemption from source reduction and waste minimization planning requirements; reduced reporting and monitoring under discharge monitoring report provisions; stringency evaluation under air programs so sites are
held to only one standard versus two; low EPA inspection priority; reduced reporting under MACT; extended hazardous waste storage time from 90 to 180 days; reduced self-inspections for certain Resource Conservation and Recovery Act (RCRA) facilities; The commission encourages all companies in the oil and gas industry to consider implementing these or any other measures which help reduce and eliminate pollution.

On February 24, 2010 the commission adopted changes to Chapter 114 to expand the Emission Reduction Incentives Grants Program of the Texas Emissions Reduction Plan. These changes include projects related to engines used for natural gas recovery. This means that if an engine can be retrofitted or replaced to reduce NOx emissions and the engine qualifies for the program, a certain amount of reimbursement is possible based on the amount of reductions achieved. The program is applicable to 41 counties in Texas, which are nonattainment counties or affected counties.

As a part of this standard permit evaluation, the commission recognizes several opportunities for OGS to prevent emissions. The most notable may be the use of a VRU to recover, instead of a flare to destroy, VOC streams and increase saleable products. In consideration of this, the commission has proposed VRUs as a control option in every possible instance where a flare or thermal destruction device may previously have been the standard option for control at OGS. The commission is proposing to allow a 95% recovery efficiency requirement, allowing for some down time and variability of the recovery process. While this is less effective at eliminating VOCs to the atmosphere than a flare or thermal destruction device at 98% destruction or better, the Commission believes the resource recovery is much more important. Unfortunately, when down time of a VRU occurs, uncontrolled emissions of crude vapors, BTEX, H2S, etc. will occur and must be accounted for with respect to the impact analysis. For some sites with a close property boundary or close neighbors the impact potential could inhibit a company from building a VRU for control. Ideally a company would use a VRU as the primary control for a site with a flare or thermal oxidizer as a back up as necessary. The commission wants to encourage resource recovery to the maximum extent possible, so comment is solicited for the best ways to encourage VRU use and on what the major barriers companies see to the use of VRUs.

IX. PERMIT CONDITIONS ANALYSIS AND JUSTIFICATION

The commission has completed a comprehensive evaluation of emissions and impacts from OGS and is proposing the new standard permit to ensure these authorization mechanisms effectively regulate emissions. The proposed standard permit applies to the specifically reviewed facilities and the operation of groups of facilities which produce, condition, process, handle and transfer petroleum liquids and gases and whose overall effects on air quality are acceptable. The proposed standard permit authorizes OGS facilities production and MSS operations and alternative operating scenarios associated with MSS which are greater than the commission’s limitations for insignificant and allows for more complex operations. However, the proposed requirements must meet emission control and health effects guidelines, and must be below the federal major NSR permitting requirement triggers (PSD and NNSR). Any OGS which cannot meet the proposed standard permit may apply for a case-by-case NSR permit. The limits of the proposed standard permit ensure protection of public health and welfare, best management practices, incentives for recovery, and practically enforceable recordkeeping.

The following discussion describes the proposed new standard permit.
Proposed subsection (a) outlines the applicability and scope of registrations under this new standard permit. The proposed subsection covers new or changed facilities (units, equipment), groups of facilities (compressor/engine/fugitive components and piping), and sites (plants/property-wide) which may use this authorization to cover several categories: new (green field) OGS; additions of facilities or groups to existing authorized sites; and changes to existing, authorized facilities, groups, or sites handling or processing petroleum liquids and gases. Based on comments received from stakeholders, both sweet and sour operations are able to use the proposed standard permit.

The majority of the proposed standard permit requirements are only applicable to new facilities or increases at existing standard permit facilities. Administrative agencies, like TCEQ, exercise power delegated to it by the Texas Legislature. It is established that statutes passed by the Texas Legislature are presumed to have prospective effect only. (TEX. CONST. ART I §16 (prohibiting bills of attainder, ex post facto laws related to penal or criminal penalties, retroactive laws, or any statute that impairs the obligations of contracts); TEX. GOV’T CODE ANN. §311.022 (Vernon 2009) (stating statutes are prospective unless expressly made retroactive)). Thus, when the legislature grants rulemaking authority to an agency, this same presumption applies. The Third Court of Appeals has held that agency rules are set for the future, and not for the past. (All Saints Health System v. Texas Workers’ Compensation Com’n, 125 S.W.3d 96, 104 (Tex. App—Austin 2003, pet. denied)). The policy behind the presumption is that retroactive application of statutes and rules does not provide fair notice and the public cannot reasonably rely on the current regulations. Therefore, the standard permit will not be applied retroactively, but will be applied to those facilities that are either newly constructed or modified after the proposed rule has been adopted by the commission.

Subsection (a)(1) allows only one standard permit to be used at any OGS to ensure a single appropriate authorization for related facilities and protectiveness of all similar emissions. This subsection allows the use of PBRs to authorize other facilities not covered under this standard permit, provided the protectiveness conditions of subsection (b)(6) are met to ensure comprehensive protectiveness of this authorization and prevent partial permitting or circumvention of these proposed standard permit requirements.

Subsection (a)(1) also prohibits the use of this standard permit to authorize operationally related facilities at a site where facilities are authorized under §116.111, General Application. To ensure that site-wide authorizations are used at an oil and gas site, facilities requiring authorization by a case-by-case permit cannot use this standard permit for new facilities or make changes to existing facilities.

Subsection (a)(2) requires owners and operators to comply with all applicable provisions of the THSC, Texas Water Code, the rules of the commission and any other applicable federal, state, or local regulation. If emissions from the OGS exceed the limitations of the standard permit, the site cannot be authorized.

Subsection (a)(3) prohibits the use of this standard permit to authorize upsets, emergencies, or malfunctions. The executive director staff believes these types of activities and releases are not appropriate to be authorized in any circumstance, and instead should be covered under §101.201, Emissions Event Reporting and Recordkeeping Requirements. Based on stakeholder comments, the commission has also included the clarification that this proposed section does not regulate methane, ethane or carbon dioxide. If the federal or state government promulgates requirements for these air pollutants, separate rules and requirements will have to be met following proposed
subsection (a)(2).
The commission’s intent in proposing this new standard permit is to ensure that new oil and gas sites or changes to existing sites appropriately focus on protection of public health and welfare, best management practices, incentives for recovery, and practically enforceable recordkeeping. Reviews under updated technical requirements will ensure facilities authorized by the executive director will meet state and federal air quality standards and guidelines based on an evaluation of all potential emissions.

Proposed subsection (b) includes several terms and phrases critical to ensuring understanding and consistency as well as outlining the scope of expected uses of this permit by rule, including federal permit applicability, standard permit registration, and protectiveness review and emission limits. State law prohibits the consideration of mines and quarries from the facility definition. The EPA, as well as the commission, considers drilling of petroleum wells to be equivalent to mining, and therefore those operations are not applicable to permitting.

The definition of facility is proposed in subsection (b)(1) for clarity, and does not change any of the commission’s other rules on facility. This term is included since there are frequent misunderstandings regarding the use of this term, and many customers and the general public use the word “facility” to describe entire plants or groups of equipment, not each individual potential emission source. State law prohibits the consideration of mines and quarries from the definition of facility. The EPA, as well as the commission, considers drilling of petroleum wells to be equivalent to mining, and therefore those operations are not applicable to permitting. In addition, while THSC §382.003(6) excludes well tests from the definition of facility, the statute continues to narrow this exception in §382.003(13) and limits the well testing time to 72 hours.

Proposed subsection (b)(2) defines receptor for purposes of complying with the emission limits of the proposed standard permit so that the emission limits paragraph is clear in its intent. For air contaminants of concern for potential health effects, measurements are made from the source of the emissions to the nearest off-property receptor. The term receptor has been defined for this standard permit to include building which was in use as a single or multi-family residence, school, or place of worship at the time this standard permit is claimed. The reason for the phrase “at the time this standard permit is registered” is to provide certainty as to when a single or multi-family residence, school, or place of worship is considered a receptor. This eliminates confusion by setting a date after which a structure is not considered a receptor for a site authorized under this standard permit.

The term residence has been defined for this standard permit as a structure primarily used as a permanent dwelling. The term residence is used throughout various statutes and rules of the TCEQ and other state agencies. However, the term is not defined under the Texas Clean Air Act (TCAA) or by air quality-related agency rules. Webster’s defines “reside” as “to live in a place for a permanent or extended time.” It further defines “residence” as “the place in which one lives.” (Webster’s II New College Dictionary, 1995) Texas courts have generally accepted that “residence” means “the place where one actually lives or has his or her home; a person’s dwelling place or place of habitation; a dwelling house.” (Owens Corning v. Carter, 997 S.W.2d 560 (Tex. 1999); Malnar v. Mechell, 91 S.W.3d 924 (Tex. App. Amarillo 2002); Dickey v. McComb Development Co., Inc. 115 S.W. 3d 42 (Tex. App. San Antonio 2003).

In most situations, whether or not a structure is a residence is generally self-evident. In some cases, however, questions may arise as to the character of a structure located near a facility in determining its compliance with applicable distance requirements. When necessary, a
determination shall be made by the TCEQ Executive Director regarding whether or not a structure is a residence. The executive director may consider factors and circumstances specific to the situation in making the determination. Potential factors that may be considered include, but are not limited to: local tax rolls showing the property as a residence; utility bills showing a residential rate; location of structure in a neighborhood with any deed restrictions or zoning ordinances on use as a business or other non-residential activity; or frequency of use of structure as a residence.

The receptor definition for this standard permit does not include structures occupied or used solely by the owner or operator of the OGS facility or the owner of the property upon which the OGS facility is located if they have a mineral rights interest in the OGS. In Texas, there are rights granted to mineral owners and surface owners. Mineral owners must be granted access to the mineral property that is theirs. To get to their mineral property, mineral owners sometimes, but not always, coordinate with surface owners. Conversely, the single or multi-family residences, schools, or places of worship that belong to surface owners who do not have such leases are considered receptors and should be protected from adverse emission impacts.

This standard permit states that all measurements of distance to receptors shall be taken from the project location which required registration under the proposed standard permit that is nearest to the residence, school, or place of worship toward the point on the building in use as a residence, school, or place of worship that is nearest to the project. This language is included to eliminate confusion on measuring distances. These are locations where the general public may congregate or be exposed to emissions for extended periods of time and these proposed standard permit limits will ensure no negative effects occur at those locations.

These definitions and language are consistent with the current air quality standard permit for permanent rock and concrete crushers. The original language is from House Bill (HB) 2912, 77th Legislative Session, 2001. The law was codified in the statute under THSC §382.065, Certain Locations for Operating Concrete Crushing Facility, and addressed concrete crushers only. The law specifically used the language “single or multifamily residence, school, or place of worship” to refer to receptors.

Subsection (b)(3) defines OGS as it pertains to this standard permit. Subsection (b)(3) highlights the critical parameters established by the commission and EPA for purposes of the federal operating permits program major source determinations. Following comments from EPA as a result of the stakeholders meeting, the commission has included the required reference of standard industrial classification (SIC) codes, facilities under common control and interest, and located on contiguous or adjacent properties.

The federal operating permit definition of oil and gas site is proposed in subsection (b)(4) for emphasis, and does not change any of the commission’s other rules on site. It is complicated to define an OGS precisely given the diverse nature of OGS activities where the well sites can cover several square miles and can be located hundreds of miles from the actual OGS processing plants. Further complicating the definition of an OGS is: land ownership; subsurface mineral rights; surface property rights; lease agreements; and site control, which are not easily distinguished in this industry. There are many considerations and memorandums issued on this subject, available through the following: http://www.epa.gov/ttn/oarpg/. The executive director also publishes a guidance document which outlines the state’s expectations for reviews (http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/Title_V/site.pdf), and due to the major source potential of OGS, this standard permit incorporates those limitations.
Current site determination involves an evaluation for all stationary sources that are located on contiguous or adjacent properties. In this case, “property” has the meaning as defined in 30 TAC §101.1, Definitions. Contiguous or adjacent properties are adjoining except for an intervening road, railroad, right-of-way, waterway, or the like. In determining contiguous or adjacent, for oil and gas activities, the surface areas on which a stationary source has been located, including any immediate area graded or cleared for such stationary sources, is considered property. Currently the commission considers properties located less than a 1/4 mile apart as contiguous. All sources must be under common control of the same person (or persons under common control). Leased properties located on tracts of land shall be aggregated if the properties are located less than a 1/4 mile apart and are under common control. As previously stated, the surface area on which a stationary source has been placed, including any immediate area graded or cleared for such stationary sources, is considered property. In addition, if a leased property and an owned property are both interdependent and under common control, these properties shall be considered contiguous and aggregated as a single site.

Subsection (b)(5) highlights the limits and scope for state authorization purposes. Registration, and all applicable requirements, under this standard permit are triggered when new facilities are proposed, or existing facilities potential to emit are increasing as outlined in proposed subsection (b)(5)(A). These new or changing facilities may be operationally related to existing, unchanging oil and gas facilities. Subsection (b)(5)(B) covers these related facilities that should be included in the new or revised standard permit registration, but are not required to meet all requirements of the proposed standard permit. Since they are not changing, the commission will not require these facilities to physically or operationally upgrade to the proposed requirements; however, the commission is proposing they should be included in the protectiveness evaluation and apply planned MSS requirements.

Subsection (b)(5)(C) specifies the scope of a registration. As with the major source determination, all OGS facilities should be included. Unlike the federal guidance, this standard permit are proposed to have a stipulated distance of no more than 1/4 mile and that the facilities under a single registration should be operationally related. The commission considers that combinations of facilities and equipments which are constructed and operate together to handle materials or make a product to be related and require a single authorization.

Based on stakeholders’ comments, the distance measurement is limited to a radius of no more than 1/4 mile from the new facilities or facilities which have the potential of increasing emissions. This distance is limited by excluding piping, fugitive components, and other similar facilities for transmission of natural gas or crude oil because OGS are often required to have isolation valves or cutoffs (fugitive components) for safety reasons by other state and federal agencies. Finally, to ensure a complete evaluation within the boundaries established, fugitive emission releases must be included for purposes of emission limits of this proposed standard permit.

Subsection (b)(5)(D) limits all OGS registrations under this standard permit to only those representations on character and quantity of emissions for any registration. This requirement mirrors §116.615, but it is often misunderstood by permit holders.

Subsection (b)(5)(E) addresses planned maintenance, start-ups, or shutdowns of OGS facilities. In 30 TAC §101.222, Demonstration, there is a clear expectation and mechanism to authorize planned MSS, with a specific schedule depending on SIC code. Although the oil and gas industry’s scheduled date is not until January 5, 2012, the proposed permit by rule relies on an
assessment and evaluation of anticipated MSS activities. It is only under these proposed
requirements and limits that MSS is authorized since no previous version of the OGS standard
permit clearly reviewed these emissions. Since there is substantially more information about these
emissions, operations and activities than in any previous point in the past, the commission is
requiring that these emissions demonstrate protectiveness. It should also be noted that MSS is not
required to be authorized and sites will not lose their existing affirmative defense opportunities
until 2012. The authorization of planned MSS associated with existing OGS does not by itself
require a notification or registration. The commission proposes to require records to be kept on
site and made available upon request. If the site has previously certified federally enforceable
emissions, an addendum to this certification may be filed to establish additional enforceable
limitations for planned MSS. This certification may be filed by hard-copy, but it is the
commission’s intent to develop an electronic E-permit system mechanism to facilitate these
updates. At this time, no fee is proposed for this certified update. No detailed review of this
information will be automatically performed, although random audits by field investigators and
permitting staff will occur.

Subsection (b)(6) addresses the obligation of permit holders to ensure protection of public health
and welfare and demonstrating compliance with applicable ambient air standards. This
requirement ensures a comprehensive perspective for the authorization fully considering the
assessment of peak and cumulative emissions and that any emissions will not cause or contribute
to a condition of air pollution. Having annual and short-term protective emission limits from all
types of activities and operations on a site-wide basis meets the fundamental criteria for
insignificance in the hierarchy of air quality authorizations and a fundamental intent of the TCAA.
In addition, the proposed site-wide perspective also satisfies EPA requirements and agreements to
assess cumulative air quality effects from related, similar sources.

Subsection (b)(6)(A) identifies the scope of the protectiveness review. To ensure all similar
emission sources under common control on a contiguous property in close proximity are evaluated,
the proposed standard permit requires all facilities, regardless of authorization type, located within
approximately 1/4 mile (1,400 feet) of a project requiring registration under this standard permit
be evaluated, including fugitive components. To ensure only appropriate review, if a claim under
this standard permit is only for planned MSS, the analysis only needs to evaluate planned MSS.
The outcome of this protectiveness evaluation establishes appropriately more stringent limits than
otherwise required by the proposed standard permit to ensure that property lines or receptors in
close proximity to the OGS are evaluated.

The proposed subsection (b)(6)(B) establishes limits on hourly and annual emissions using the
various requirements and options in subsection (k) and the tables in subsection (l). There are
numerous ambient air quality standards applicable to the emissions associated with an OGS,
including NOx (hourly NAAQS 188 µg/m³, annual NAAQS 100 µg/m³), CO (hourly NAAQS
40,000 µg/m³), SO2 (new hourly NAAQS 196 µg/m³, most stringent state 30-minute standard 715
µg/m³), PM10 (24-hour NAAQS 150 µg/m³, annual NAAQS 50 µg/m³), PM2.5 (24-hour NAAQS
35 µg/m³, annual NAAQS 15 µg/m³). Hydrogen sulfide does not have a NAAQS standard, but is
regulated by 30 TAC §112 (most stringent state standard 108 µg/m³, statewide standard 162
µg/m³). Also present at OGS, but are not limited to, are benzene, toluene, and xylene. These
constituents must meet their respective effects screening levels as shown at:
http://www.tceq.state.tx.us/implementation/tox/esl/list_main.html. Specific compliance
demonstrations of certain air contaminants are not required for any individual registration based an
analysis of the protectiveness review and a large number of OGS registrations recently reviewed
by the commission.
The commission proposes to limit the evaluation to 2,700 feet based on the commission’s consideration of distance limits for contiguous properties and operationally related facilities; the highly conservative nature of the model and modeling approach discussed in the Protectiveness Review section; and the commission’s intent to establish conservative emission rates and site-wide limits to address the requirements of various air quality permitting programs. In addition, it is the commission’s experience that worst-case modeled concentrations from the facilities authorized by this rule do not occur under actual operating and meteorological conditions and are not measured at the values predicted at distances beyond approximately 1/2 mile.

Based on the impacts analysis performed by the commission, it is extremely unlikely that any OGS will have or contribute to an exceedance of the CO 1-hour or 8-hour NAAQS; therefore, a registration-specific impacts analysis is not necessary or required by this proposal. Also based on this information, it is extremely unlikely that any OGS will have or contribute to an exceedance of any PM_{10} or PM_{2.5} NAAQS; therefore, a registration-specific impacts analysis is not necessary or required by this proposal. The analysis of NO_x and the hourly NO_2 NAAQs shows that applicants should be required to demonstrate acceptable impacts for distances between 50 feet and 2,700 feet for all combustion sources greater than 9 lb/hr. Based on actual registration information, it is anticipated that most, if not all, engines should meet the formaldehyde standards and therefore no specific hourly evaluation is required. Furthermore, compliance with the hourly limits is compliance with the annual limits as well, so no additional demonstration is needed for any individual registration.

The analysis for SO_2 shows that most sweet sites will meet the new, more stringent NAAQS, regardless of having distances greater than 2,700 feet. For sites with emissions greater than 3.4 lb/hr, clear compliance demonstration with the new NAAQS cannot be determined unless further analysis is performed. In addition, it is the commission’s experience that predicted concentrations do not actually occur and are not measured at the values predicted at distances greater than 2,700 feet from a source. Therefore, applicants should be required to demonstrate impacts of SO_2 for distances between 50 feet and 2,700 feet for SO_2 sources. Based on actual registration information, it is anticipated that most H_2S sources should meet the applicable H_2S state ambient air standard. In addition, it is the commission’s experience that predicted concentrations do not actually occur and are not measured at the values predicted at distances greater than 2,700 feet from a source. Therefore, applicants should be required to demonstrate impacts of H_2S for distances between 50 feet and 2,700 feet for H_2S sources greater than 0.03 lb/hr. It should be noted that 30 TAC Chapter 112, may have more stringent requirements due to the differences in the definition of receptor.

Finally, the evaluation of VOCs shows that benzene, toluene and xylene need to be evaluated for distances to receptors between 50 feet and 2,700 feet.

Proposed subsection (c) establishes the expectations for authorizations of new facilities, changes to existing facilities which increase emissions, and newly authorized activities of facilities which result in emissions.

Paragraph (c)(1) covers various possible changes at existing OGS. Subsection (c)(1)(A) covers situations where new facilities are added to an OGS, registration of those facilities is required following paragraph (b)(5). When changes occur to existing facilities which increase their potential to emit, or increase emissions above previously certified emission limits, registration of
those facilities is required following paragraph (b)(5). In both of these circumstances, the new and changing facilities must be evaluated under all portions of the proposed standard permit. At those same sites, other facilities which are not affected by the new or changing facilities are not required to meet the requirements of the proposed standard permit. However, existing unchanged facilities must be included in the site-wide protectiveness evaluation.

Subsection (c)(1)(B) covers very small possible changes at existing OGS and establishes appropriate minimal requirements and waives full registration and review. Common changes at OGS include updating and adding sections of piping, associated fugitive components, and small equipment additions. Additionally small engines (up to 100 hp) are often added to supplement other equipment operations. These types of changes are inconsequential when considering all other potential and actual emission sources at an OGS. These types of changes are also commonly made, and placing registration, notification or other proscriptive requirements is burdensome and unnecessary in the commission’s opinion. The negligible increases proposed by the commission would be limited to emissions less than or equal to 1.0 tpy VOC, 5 tpy NOx, 0.01 tpy benzene, and 0.05 tpy H2S. These values were established well below any applicable threshold and should not contribute to any impact evaluation exceedances. These increases are also limited to a rolling 12-month period because the commission does not want to authorize perpetual changes at an OGS without agency review or compliance demonstrations. To ensure proper operation and accurate accounting, these negligible changes and additions would be required to follow best management practices, keep records, and not result in changes at other facilities at the site or increase the OGS potential to emit air contaminants.

Finally, if there are many changes over time, the rule and this language do not define what the amount of time is, the commission has proposed to limit the total amount of changes to 5 tpy VOC or NOx, 0.05 tpy benzene, or 0.1 tpy H2S. The values proposed for VOC and NOx are based on the most stringent federal NSR applicability trigger (the point at which a major site in a designated nonattainment area would be required to complete a contemporaneous netting exercise). After any one of the limits is met, a registration (or registration update) under this standard permit would be required so that all appropriate standard permit requirements can be assessed. These values will allow some limited flexibility of operations, but does not allow any potential threshold for major source evaluations in the most restrictive of a designated nonattainment area to be exceeded. These levels will also ensure that increases in sulfur compounds or VOCs would be periodically evaluated for protectiveness. Any negligible changes or additions must be incorporated at the next registration or certification under the standard permit.

Proposed subsection (c)(1)(C) covers like-kind replacement of existing facilities under very specific circumstances. If all requirements are met, the entire OGS does not need to undergo a full review since under these limited circumstances it is not appropriate or necessary for protectiveness of continuing OGS operations. The first criteria is that the new replacement facility must have the same or less emissions than the facility being replaced. Next, there can be no other effect on the OGS’s emissions. The replacement facility cannot trigger any federal NSR review requirements and must comply with any applicable state or federal standard. Finally, the replacement facility must be incorporated into the standard permit registration or file at the next revision or renewal. With these options at existing authorized OGS, the industry is given flexibility to be responsive to resolve equipment problems before failures and upsets occur and the commission is minimizing unnecessary paperwork and resources for non-substantial changes. Additionally, replaced facilities cannot exceed major source or major modification thresholds.

Proposed (c)(1)(D) does allow other insignificant changes to occur at an OGS under a standard
permit. If the changes could meet 30 TAC §§106.261 and 106.262 and the emission limitations of the new proposed standard permit, the change will be allowed without requiring a complete review under the new standard permit requirements. The commission has determined that a full review under these limited circumstances is not appropriate or necessary for protectiveness of continuing OGS operations. Proposed (c)(1)(A)(iii) requires applicants who cannot meet the requirements of the standard permit to use another authorization for the entire OGS (PBR or case-by-case permit).

The proposed (c)(1)(E) includes a requirement to meet 30 TAC §116.605. This rule requires that holders of previous version of a standard permit which has been amended, upgrade their sites to the new amended requirements at the next renewal. This rule does allow for a delay and the commission has proposed approximately 4 years from the expected effective date. Based on the current rule requirements under 30 TAC §116.610(a)(1), there is no overwhelming reason to believe that there would be any health effects by waiting to implement the changes in new requirements under §116.610. The current standard permit establishes protectiveness limits, requiring that companies verify compliance with 30 TAC §§106.261 and 106.262. The current rules limit facilities to certain quantities of hourly and annual emissions based on their distance to the nearest off-site receptor, just not an industry-specific one as proposed in the new standard permit.

Subsection (c)(2) ensures that the standard permit does not authorize OGS which should obtain a PSD or NNSR authorization. This subsection also reminds companies that compliance with all state and federal requirements applicable to units and facilities at the site must be complied with.

Proposed subsection (c)(3) also covers situations where some facilities, or groups of facilities, at the site have been authorized under versions of the OGS standard exemption and permits by rule. This is a common situation as many production sites have grown over time, adding new units and production capacity and claiming various rules in effect at the time. To ensure the site-wide emission impacts are protective of public health and welfare, the commission proposes to require all of the facilities covered by PBR at the site be incorporated into this standard permit at any registration, revision or renewal under new proposed standard permit. Existing PBR registrations if applicable will be voided in tandem with approval of the oil and this standard permit registration. These previously permitted by rule facilities would be: included in assessments of impacts and emission limits; required to follow best management practices; follow all planned MSS requirements; keep records and compliance requirements; and included in the allowable table issued with any registration. These facilities would not be subject to other BACT requirements until a change occurs which increases air emissions potential to emit, production capacity, or exceeds an enforceable emission rate.

Subsection (c)(4) requires that any registration for the standard permit will be subject to the requirements of 30 TAC Chapter 60, Compliance History. If an existing OGS has a history of noncompliance, and if there are overwhelming concerns of public protectiveness or other issues which need to be addressed, the executive director may not accept a registration or certification under this standard permit. This condition is not expected or anticipated to be used on a frequent basis, but for extreme circumstances when deemed necessary. The commission proposes subsection (c)(3) to establish a clear understanding by the regulated community that if an existing OGS has a history of noncompliance, there are overwhelming concerns of public protectiveness or other issues which need to be addressed, the executive director may deny a registration or certification under this standard permit for good cause. In this subsection, the reasons that constitute “good cause” include: failing to meet the requirements of the standard permit; violating any term or condition of the permit; having a record of environmental violations in the preceding
five years at the permitted or exempted site; causing an emission contravening a pollution control standard set by the commission or contravening the intent of a statute or rule within the commission’s jurisdiction; including a material mistake in a federal operating permit issued under THSC Chapter 382, or making an inaccurate statement in establishing an emissions standard or other term or condition of a federal operating permit; misrepresenting or failing to disclose fully all relevant facts in obtaining the permit or misrepresenting to the commission any relevant fact at any time; a permit holder being indebted to the state for fees, payment of penalties, or taxes imposed by the statutes or rules within the commission's jurisdiction; a permit holder failing to ensure that the management of the permitted facility conforms or will conform to the statutes and rules within the commission's jurisdiction; abandoning the permit or operations under the permit; or when the commission finds that a change in conditions requires elimination of the emissions authorized by the permit.

Proposed subsection (d) establishes which facilities are authorized under this standard permit. Proposed subsection (d)(1) specifically lists all facilities and sources considered in this evaluation. In accordance with comments from EPA, any standardized authorization mechanism must be unit-specific and not allow any uncertainty or unforeseen facility authorization. The commission is seeking comments on the inclusiveness of all common facilities at oil and gas sites traditionally using this standard permit so a comprehensive review can be assured. The commission has evaluated numerous facilities, along with supporting infrastructure equipment for this permit by rule, including: fugitive components, including valves, pipe flanges and connectors, seals, instrumentation, and associated piping; pumps and meters; separators, including gun barrels, free-water knockouts, oil/water, and membrane units; condensers for process operations; treatment and processing, including heater-treaters, methanol injection, glycol dehydrators, molecular or mole sieves, amine sweeteners, SulfaTreat®, and iron sponge units; cooling towers; gas recovery units, including cryogenic expansion, absorption, adsorption, heat exchangers and refrigeration units; combustion units, including engines, turbines, boilers, reboilers, heaters and heater-treaters; storage tanks for crude oil, condensate, produced water, pressure tanks with liquid petroleum liquids, fuels, treatment chemicals, and slop and sump oils; underground storage of gas or liquids and associated surface support facilities; truck loading equipment (except for vacuum truck loading equipment); control or recovery equipment including vapor recovery systems, condensers for control or recovery, flares, vapor combustors, and thermal oxidizers; and temporary facilities used for planned maintenance, and temporary control devices for planned start-ups and shutdowns (except for planned MSS degassing operations). The commission requests comments on the use of various truck types and liquid loading operations at OGS and on planned MSS degassing operations.

Proposed subsection (d)(2) also lists the types of facilities and operations that are not authorized by this standard permit. Several units and operations were excluded for various reasons for consideration under the standard permit. Subsection (d)(2)(A) discusses SRUs which are not authorized because it was discovered that when an SRU was pulled out of service for maintenance, the emissions typically exceed PSD significance levels. This represents a major source as defined in §116.12, which cannot be authorized by a standard permit. The only way to prevent triggering federal PSD requirements is to maintain a second SRU to switch over during maintenance operations. Since the reviewed permitted OGS did not reveal any dual SRU units, it was concluded by the executive director staff that the industry was reluctant to invest in the capital outlay, and consequently SRUs were excluded from the evaluation. Sour water strippers, which are used to remove hydrogen sulfide from water, were not evaluated for protectiveness since they are associated with SRUs. In proposed subsection (d)(2)(B), carbon dioxide hot carbonate processing units were excluded since the executive director staff was not able to obtain sufficient
processing and emission data for production, or maintenance, startup, and shutdown emissions on these units from applications it reviewed. As a result the executive director staff was not able to evaluate these units. The commission requests comments on carbon dioxide hot carbonate processing units and will evaluate accordingly.

The commission also proposes in subsection (d)(2)(C) to exclude water injection facilities from authorization under this standard permit. These are subsurface facilities involved in waste disposal activities, which are beyond the scope of the oil and gas site production processes at the sites evaluated. Instead, many of these facilities and operations can claim permit by rule §106.351. Transfer of liquefied petroleum gases (LPG), crude oil, or condensate by railcar, or marine barges was also excluded in subsection (d)(2)(D) as these operations were not found at sites in the executive director staff’s review because larger oil and gas sites use pipeline transfer for economic and geographical reasons. However, if these operations occur on a small scale, other PBRs may be claimed, such as by §§106.261 and 106.262. Proposed subsection (d)(2)(E) excludes solid waste incinerators because they were rarely found in evaluations of existing authorized PBR and standard permits. The resources required for a comprehensive evaluation of potential emissions, control specifications, and impacts were determined to be unnecessary as a part of this proposal. In proposed subsection (d)(2)(F), remediation of water and soil as a result of petroleum spills is excluded. These activities can be independently authorized under §106.533, Remediation, and in some cases, are covered by the Texas Railroad Commission regulations. Proposed subsection (d)(2)(G) excludes direct contact cooling towers or heat exchangers to ensure that VOC and other air contaminants are not stripped from waste or product streams and inadvertently emitted to the atmosphere. Additionally, the commission has determined that direct contact cooling towers or heat exchangers is not good engineering practice for OGS. The proposed subsection (d)(2)(H) also prohibits use of the standard permit in an Air Pollutant Watch List (APWL) area for any applicable APWL contaminants for that area. The need to more strictly control air pollutants in these areas justifies a case-by-case review. In this way, standard permit authorizations will not contribute to existing, monitored problems in specified areas of the state.

The commission proposes subsection (e) to require best management practices and minimum requirements for new and changed facilities at an OGS authorized under this proposed standard permit. These requirements are not applicable to existing, unchanged facilities at an OGS. For new and changing facilities, design and operation requirements are needed to prevent emissions from being generated or escaping from these sources. To emphasize the importance of BMP, proposed subsection (e)(1) reiterates the regulatory requirements from §101.221, Operational Requirements, for keeping all facilities’ capture, recovery and control equipment in good working order. This is essential to ensure that facilities are meeting authorization limits. This subsection also requires sites to establish a program for replacements, repairs and maintenance on facilities. Cleaning and inspection in (e)(1)(B) does not include degassing, which is separately addressed in the proposed rule. The commission has determined that replacements, repairs, and maintenance of equipment is good engineering practice and necessary to ensure minimization of emission releases.

Proposed subsection (e)(2) discusses that any control device downtime must be evaluated and if needed, waste streams redirected to other controls. The commission has determined that analysis of back-up and redundant control systems are inherent in any good operation design.

Proposed (e)(3) requires a minimum 50 feet to the nearest property line or receptor. This is the limit of the modeled impacts, and should provide a reasonable buffer considering the potential location of many OGS throughout Texas. In the rare circumstance of a receptor on the site itself, 50 feet from the receptor to the nearest facility would still be needed. Existing fixed immovable
facilities would be exempt from this distance limitation even if they are modified, since it is unfeasible to move these facilities. Furthermore, any valve that is for isolation and or safety purposes must be at least 25 feet from any receptor to parallel standards set forth by the Texas Railroad Commission. The commission has also clarified that this distance is not applicable if a receptor is subsequently built within this buffer zone.

The proposed subsection (f), General Requirements, outlines facility design, operation, and emissions control criteria. As required by statute, the proposed standard permit requires all new facilities authorized under this standard permit to meet BACT requirements. Also consistent with the wording and intent of the TCAA, the commission is proposing to require all changes at existing authorized facilities which have the potential to increase emissions to also meet BACT requirements. Proposed (f)(1) refers to several tables attached to the standard permit. Tables, located in subsection (l) of the standard permit, are used due to the level of detail needed for the wide variety of equipment and operations expected at an OGS.

Subsection (f)(2) is proposed to outline requirement for engines and turbines. Table 9 specifically lists emission standard requirements. To eliminate confusion over when an OGS must register or notify the commission, and to account for engine and turbine rules and requirements that are not accounted for in §106.512, the proposed language supersedes the requirements of §106.512. Instead, new or modified engines and turbines must meet specific NOx, VOC and CO requirements. These criteria are based on Tier I BACT determinations, current Chapter 117, requirements and federal new source performance standards. The proposed BACT in Table 9 contains a schedule for upgrading engines based on the previous discussion in this document. Rich-burn engines authorized by this standard permit will have until January 1, 2015, to upgrade while engines installed after that date will have one year to upgrade. Lean-burn Engines that exist on the site as of January 1, 2012, will have 8 years to be retrofitted or replaced while engines brought on site after that date will have three years. Finally, this subsection requires operators to follow the more stringent or additional requirements, regardless of this proposed section. These requirements include Chapter 117 and various NSPS and MACT standards. The commission also notes that the proposed standard permit does not authorize engines used for drilling purposes. In almost every instance, these engines do not remain on the site for 12 consecutive months, and therefore are not considered stationary sources needing an authorization consistent with EPA guidance and TCEQ determinations.

The proposed subsection (f)(3) outlines the requirements for fugitives and refers to Table 10 which outlines the BACT expectations for the LDAR program, applicable at sites with 10 tpy VOC.

Proposed subsection (f)(4) lists the requirements for all process equipment and storage facilities and refers to Table 11. This table identifies specific facilities and control expectations, as well as site-wide considerations.

The first row of Table 10 lists a site-wide requirement, which is clarified by (f)(4). The TCEQ believes that at a combined emission potential of 25 tpy VOC or more, the cost of the flare or other combustion control with some additional piping and gas moving cost is reasonable, and at oil and gas sites the potential for dramatically greater percentages of methane and ethane in the streams makes the combustion control even more reasonable. At 25 tpy over a 15 year life of the control device achieving 98% control would control 367.5 tons of VOC. At a low end Tier III BACT analysis for VOC control of $8,000 per ton of control that equates to a cost of control of over 2.9 million dollars for the equipment and annual operating cost. This could cover equipment costs to a million dollars with operating costs at $10,000 per month. While the TCEQ believes this makes
control of combined smaller streams of this magnitude appropriate BACT, the commission is soliciting detailed information on actual current costs of flares, piping and other gas handling and safety equipment to better assess our estimates and evaluate if the combined stream requirement is too high or too low at 25 tpy. The TCEQ recognizes however that there could be sites with some very small streams that may contain more than 1% VOC that just considering the cost of piping would be impractical to control. The commission is soliciting comments with detailed information on the specific type and size of streams and the piping equipment costs where a control device would be available but connection to the device is impractical.

Table 10 continues to discuss the BACT expectations for glycol dehydrators. These units have minimum design and operational restrictions. The dehydrators are a common facility at OGS and have the potential for high hourly emissions of BTEX. If the potential of a glycol dehydrator is greater than 10 tpy VOC, the design and operational requirements should reduce total VOC and BTEX emissions by at least 80% and as much as 98%. The amine units also have concentrated waste streams of sulfur compounds. Due to these high potential emissions, the commission proposes to minimize the emissions from these process vessels once a substantial amount may be emitted. Tier I BACT for amine units is to send them to a flare (98% efficiency) or thermal oxidizer (99%). For process separators, the potential of VOC emission is minimized consistent with current permit BACT determinations and vents must be captured and directed to an appropriate control device with a minimum design control efficiency of 95%. Oil and water separators must have any sour stream controlled to 98% reduction in sulfur emissions. If separators have VOCs with partial pressure of $\geq 0.5$ psia must be controlled to a 95% VOC control efficiency. To encourage recovery, the commission has proposed at least 95% control to allow for VRUs if technically feasible for these types of equipment.

Fuel for all combustion devices is limited to sweet gas or liquids to minimize potential emissions of SO₂ and maintain engine components for proper operation. Manufacturers of burners for boilers, reboilers, heater-treaters, and process heaters less than 40 MMBtu/hr firing rate have developed and companies have been using low NOx burners that achieve 0.036 lb NOx/MMBtu for several years. TCEQ has required these burners as BACT in recent case by case permits. Manufacturers have created burners that do not need flue gas recirculation (FGR) to achieve 0.036 lb NOx/MMBtu and this has reduced the cost and installation problems for many facilities making it technically feasible for units that previously could only meet 0.06 lb NOx/MMBtu because FGR was not possible. CO emissions tend to be well below 100 ppm on average with only occasional spikes. This allows for consistent low NOx performance. This has been accepted as Tier 1 BACT.

Burner design has advanced in the past five years and manufacturers have developed ultra low NOx burners for larger combustion units (>40 MMBtu/hr firing rate) and the TCEQ has permitted several facilities using this technology. The TCEQ recently approved a standard permit for boilers which requires 0.01 lb NOx/MMBtu. The TCEQ is not aware of a technical limitation to applying this standard to units that are not strictly defined as boilers but use similar burners since these are burner designs and not boiler only technology. Manufacturers achieve ultra low NOx in part through the use of internal or external FGR which is why it is not technically feasible for small units. CO emissions have remained low with the newer burners and current Tier 1 BACT is 50 ppm.

Based on the commission’s evaluation of actual site conditions and input from stakeholders, many OGS have open-topped tanks and ponds which are integral to site operations. In appropriate situations, these open tanks and ponds are acceptable and will only contribute in a negligible way
to the site’s emissions. In other cases, the amount of hydrocarbon liquids entrained in open-topped tanks and ponds may be sufficient to potentially result in a substantial amount of VOCs and H2S emissions as the open-topped tanks or ponds are exposed to the evaporative effects of the sun and wind. Therefore, some reasonable limit is considered above which closed tanks are necessary. The commission is proposing that limit to be 1 tpy VOC and 0.1 tpy H2S.

The BACT tables of the standard permit include proposals to require certain tanks, process vessels, and temporary liquid storage tanks containing VOC and H2S to be painted white. Tank color plays an important role in accelerating or minimizing VOC emissions from tank working and breathing losses. An estimate of emissions from working and breathing losses was calculated to evaluate the effect of color choice on the emissions from a storage tank and showed a 42% increase in VOC, benzene and H2S emissions when a tank was red (or rust). In a typical tank example emission are released up to more than a ton more of total VOCs per year. While the argument has been made that solar absorption may not make a significant contribution to the amount of emissions from a single process vessel or storage tank, the results clearly demonstrate the paint color used is significant for emissions from working and breathing. It is estimated that there are tens of thousands of these tanks throughout Texas. Painting tanks with a low solar absorption rated color such as white will result in a significant cumulative reduction in statewide emissions. This has state-wide implications especially for counties currently in nonattainment areas or near-nonattainment areas. These results are consistent with the TCEQ Chemical Sections’ previous BACT and BMP determinations of the last 20 years. The BACT requirement affecting temporary liquid tanks is a more recent determination, but these tanks can substantially contribute to VOC and H2S emissions released throughout the state. In order to ensure air quality, all facilities authorized must minimize emissions to the greatest reasonable extent, thus the commission has considered proposed requirements to address color for permanent and temporary liquid and gas tanks and vessels which have a potential of 5 tpy VOC or are handling materials with a vapor pressure of 0.5 psia.

To effectively minimize the generation of air contaminants, tank color should be white or reflective because potential emissions from any storage or process tank are directly proportional to its color. Condensor columns are exempt because they are purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor. The commission is asking for comment or information concerning other vessels or tanks which, by their function at an OGS, need to be considered for exemption from the color requirements.

The commission proposes to establish the white or reflective color requirement for all new permanent tanks and vessels, or existing tanks and vessels with an increase in emissions. To further ensure air quality is preserved, all other existing tanks and vessels, plus all temporary liquid storage tanks brought to the OGS, must also be white by certain dates. The commission realizes that there may be thousands of existing tanks which may need to be painted after this proposed standard permit becomes effective. The commission also recognizes that it is reasonable to offer a period of time to allow identification and inspection of all affected tanks, coordination with contractors and landowners, obtaining supplies, and completing the color adjustment. Therefore, the proposed subsection allows for up to 6 months a renewal processed after January 1, 2016.

The standard permit also proposing certain requirements for truck loading to minimize emissions. Consistent with the BACT discussion above, the commission is establishing capture and control requirements listed in Table 11. Finally, the proposed standard permit includes requirements so that cooling water never comes in direct contract with petroleum liquids or gases at the OGS, thus preventing emissions from being released into the atmosphere. This is a reasonable requirement.
and a basic engineering design and operation expectation to ensure cooling towers and boiler cooling water equipment is in good working order.

Proposed subsection (f)(5) lists the requirements for control devices as detailed in Table 12. Two common control systems used at OGS are vapor recovery units and thermal destruction units. The commission establishes the expectations for VRUs. A VRU is a system composed of a scrubber, a compressor and a switch. Its main purpose is to recover vapors formed inside completely sealed crude oil or condensate tank. The switch detects pressure variations inside the tank and turns the compressor on and off. The vapors are sucked through a scrubber, where the liquid trapped is returned to the liquid pipeline system or to the tank, and the vapor recovered is pumped into gas sales lines. Properly maintained, appropriately sized, designed, and operated VRUs can achieve up to 95% recovery when operating and allow only minor amounts of VOC to escape through fugitive components of the piping. The design specifications proposed rely on sizing the unit to handle unexpected conditions where the volume typically expected from vessels being controlled may increase. This is to ensure the VRU can handle conditions when increased temperature and pressure combine to release above average emissions. Additionally, hatches and valves must be equipped with the appropriate gaskets and seals to prevent leaks. Based on this information and research provided by the EPA, the commission is willing to accept 95% control efficiency for VRUs. However, in order for the commission to accept claims of control efficiencies of 95%, records must include detailed records demonstrating; either a single or two-stage VRU has been installed, operating pressure and temperature of the separator releasing into the tank being controlled, pressure within the tank, oil composition and API gravity, tank operating characteristics (e.g. flow rate, size of tank), and ambient temperature. This information can be found in the latest E&P Tanks 4.0 program and is important in order to determine the exact changes occurring before, during, and after fluids are added to the tank. Additionally, in order for the commission to accept and claimed control efficiencies greater than 95% applicant must provide an analysis with a clear demonstration of claimed control efficiency.

Thermal destruction units used at OGS include flares, thermal oxidizers, and vapor combustors. The proposed standard permit requires that flares be designed and operated in such a way that ignition of the flare tip and proper combustion of the stream is achieved. Proper design and maintenance of the flare will insure that the stream going to the flare will be combusted and the emissions controlled. These requirements insure that the flare being used to control emission limits will meet the emission limits of the standard permit, including: flare tip, velocity, heating value, and opacity requirements of §106.492, Flares, and 40 CFR §60.18. Requiring sufficient heat content of the waste gas plus assist gas stream, continuously burning pilot or auto-ignition system, and smokeless operation ensures that the flare operates at the optimum 98% VOC destruction and 100% H2S conversion to SO2. To achieve this performance, flares require the appropriate amount of waste and fuel flow for complete combustion to occur in the flame zone, but not so much that the stream passes through the zone un-combusted. These requirements should be used by any flare at an OGS. This is important when typical operations are considered and effective control of emissions is needed. For example, when wells are flooded with CO2 and resulting emissions vented to an emergency/upset flare, many units that are not designed or operated correctly will not ignite, and no control is achieved. This paragraph also requires all flares to be lit when receiving any waste gas stream (production, planned MSS or emergency/upset). Although this may seem inherently understood as a basic operational necessity, this requirement is not specifically addressed in 40 CFR §60.18 or §106.492. Having the flare lit is essential to the proper performance of the device in controlling emissions.

Thermal oxidizers are more efficient control devices using a firebox and controlled inlet flows but
are less common at OGS. The proposed standard permit states the expected destruction efficiency of 99.9% if operated at a 1,400 °F minimum operating temperature and a minimum residence time of 0.5 sec in the firebox. This design has become commonly available and is equipped with continuous temperature monitors. This is an extremely effective destruction device, but only if operated properly and maintained in good working order.

Vapor combustors are not included in this proposal. Owners and operators of OGS have stated that the use of these devices is becoming more common. These units can be a wide variety of designs and operations and no clear operational procedures seem to be common to all possible control units in this category. The commission is seeking comments on details relating to vapor combustors to establish typical and consistent design, operations, and compliance monitoring requirements so that they may be included as a control option with appropriate limitations and expectations.

Condensers may reduce emissions by 80% or more. They function on the change in temperature allowing condensation of liquids from a gas, thus minimizing vapor and pollutants being released to the atmosphere. Since temperature plays a critical part in this reaction, a temperature monitor and records are important to ensure this unit is meeting expectations. If greater than 80% is claimed for a unit, the proposal requires a sample to demonstrate the claimed effectiveness.

The TCEQ encourages pollution prevention, specifically source reduction, as a means of eliminating or reducing air emissions from industrial processes. Sites should consider opportunities to prevent or reduce the generation of emissions at the source whenever possible through methods such as product substitutions, process changes, or training. Considering such opportunities prior to designing or applying “end-of-pipe” controls cannot only reduce the generation of emissions, but may also provide potential reductions in subsequent control design requirements (e.g., size) and costs.

Proposed subsection (g) outlines the expectations for registration of new facilities and sites, as well as notification for changes. The registration requirements are modified from the current OGS standard permit to provide flexibility and only necessary processing of paperwork by industry and the TCEQ. In addition, based on the current status and evaluation of the oil and gas industry, the registration and notification requirements are appropriate, and this Standard permit supersedes the notification requirements of 30 TAC §116.615 for changes to OGS standard permit. Subsection (g)(1) specifically notes that this proposed standard permit supersedes 30 TAC §§ 116.610, 116.611, 116.614, and 116.615.

Proposed (g)(2) requires operators of new OGS seeking authorization of new facilities to register for this standard permit before construction or implementing operational changes. This will ensure that the new requirements for design, capture, control and protectiveness are met as these existing sites expand operations or authorize MSS activities for the first time. Proposed (g)(3) allows modifications which increase emissions of existing authorized facilities or modification of facilities or operational changes that will cause changes in the character of emissions to submit a revised registration no later than 30 days after the change is implemented. In proposed (g)(4), similar to the current standard permit, registration for a new OGS is always required. Companies claiming the proposed standard permit for new facilities and sites are required to register prior to construction or changes are implemented, including documentation on how facility emissions are estimated. This requirement ensures that for these OGS with larger potential emissions that the executive director has the opportunity to audit emission estimates. Although certain information important to making an accurate estimate of potential emissions may not be confirmed prior to
construction, specific site-wide data should be confirmable within 180 days of start of operation. To further ensure and confirm compliance, proposed (g)(4) requires updated emission estimates within a reasonable period of time from start of operation. The start of operation of a new OGS will be considered to be the point in time that facilities which are the potential source of air contaminants are on-site, performed their intended function, and after the well-test period has passed. THSC §382.003 defines the well-test period as 72 hours.

Proposed subsection (h) addresses overall limits for an OGS under standard permit based on the largest amounts of air emissions which have been shown by the commission’s impacts analysis to be protective and meeting ambient standards.

Proposed subsection (h) limits the hourly and annual emissions for OGS registered under this standard permit based on the protectiveness review and impacts tables completed by the commission. Total VOCs are limited to 200 lb/hr and 250 tpy. The hourly limit is based on impacts Table 1 at 2400 ft and 30 ft process vent assuming emissions meet the ESL for condensate or crude oil. The 250 tpy is the maximum amount without triggering PSD, and is less than the impacts at 2700 ft at a 60ft stack for condensate or crude oil ESL. Additionally, subsection (h)(1)(A) limits benzene to 20 lb/hr and 10 tpy. The 20 lb/hr based on impacts Table 1 at 2700 ft and 60 ft process vent for one times the hourly ESL, while the 10 tpy based on maximum amount not to be considered major for single HAP, also impacts Table 1 at 1800 ft with 30 ft process vent one times the annual ESL. Subsection (h)(1)(B) limits toluene at 35 lb/hr toluene and 10 tpy. The 15 lb/hr based on impacts Table 1 at 2700 ft and 60 ft process vent one times the hourly ESL and 10 tpy is based on maximum amount to not be considered major for single HAP, also impacts Table 1 at 1800 ft with 30 ft process vent one times the annual ESL. Subsection (h)(1)(C) limits xylene to 19 lb/hr xylene and 10 tpy xylene. The 10 lb/hr based on impacts Table 1 at 2700 ft and 60 ft process vent one times the hourly ESL, and 10 tpy is based on maximum amount to not be considered major for single HAP, also impacts Table 1 at 1800 ft with 30 ft process vent one times the annual ESL. Subsection (h)(1)(D) limits formaldehyde to 3 lb/hr and 10 tpy. The 3 lb/hr based on impacts table for engines > 1000 hp at 2700 ft and 40 ft vent one times the hourly ESL, and 10 tpy based on maximum amount to not be considered major for single HAP.

Subsection (h)(2) covers sulfur compounds. Subsection (h)(2)(A) limits H2S to 6 lb/hr and 15 tpy H2S. The 6 lb/hr based on impacts Table 1 at 2700 ft and 60ft process vent hourly 1x hourly standard and 15 tpy based on impacts Table 1 at 2700 ft and 50 ft process vent steady-state hourly to annual and 1x hourly standard. SO2 is limited to 12 lb/hr and 50 tpy. The 12 lb/hr based on impacts table for flares at 2700 ft and 60 ft flare release height new hourly standard 50 tpy based on impacts table for flares at 2700 ft and 60 ft flare release height and new hourly standard converted assuming steady-state hourly to annual releases.

Finally, products of combustion are limited. NOx is limited to 53 lb/hr and 250 tpy. The 53 lb/hr based on impacts table for engines > 1000 hp at 2700 ft and 40 ft vent new hourly NAAQS and 250 tpy is based on maximum amount without triggering PSD. CO is limited to 57 lb/hr and 250 tpy. The 250 tpy is based on maximum amount without triggering PSD, and 57 lb back calculated from 250. The limit of 4 tpy PM10/PM2.5 is well below any applicable NAAQS and less than any OGS registration seen by the commission to date.

Proposed subsection (i) lists specific MSS activities authorized and the associated limits. Subsection (i)(1) lists the applicability dates and schedules for authorizing planned MSS activities, and notes that authorization under this standard permit is voluntary until January 5, 2012. For existing, properly authorized, oil and gas sites, MSS emissions do not need to be addressed until
January 5, 2012, unless modifications are made. If modifications are made to an existing oil and gas site on or after the applicable effective date of the proposed standard permit, then MSS activities and associated emissions for that site need to be either registered or addressed in a registration. The commission has limited information on the various planned MSS activities which occur throughout the diverse oil and gas industry and is requesting comments and technical information on activities and potential emissions from planned MSS.

The commission proposes (i)(2) to ensure that all chemically common emissions are evaluated for protectiveness. Emissions from control devices used for planned MSS (permanent or portable) are included for emission limits evaluation. The VOC for planned MSS emissions under worst-case operating conditions and all contributing emissions must be evaluated for total hydrocarbons as condensate, natural gas, and benzene. This paragraph specifically lists the most commonly expected activities which may contribute to emissions during these events. In most cases, emissions from blowdowns or purging do not occur simultaneously with production emissions, so the weighted fraction method of impacts evaluation is not commonly needed. There are certain expected planned MSS activities and associated emissions which also have the likelihood of quantifiable hourly and annual emissions.

Planned MSS activities with negligible emissions would be authorized by proposed subsection (i)(3) and are limited to the following: routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance in combination with any other activities; boiler or thermal oxidizer refractory replacements and cleanings; heater and heat exchanger cleanings; lubrication oil level checks; amine filter replacements; glycol draining and refilling; pump, compressor, heat exchanger, vessel, water treatment systems (cooling, boiler, potable), and fugitive component maintenance after associated blowdowns and degassing; use of aerosol cans, soap and other aqueous based cleaners; pressure relief valve testing; calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens; and cleaning sight glasses. These other planned MSS activities require recordkeeping, but no emissions quantification unless specifically requested by the executive director. Other planned MSS activities with negligible emissions are based on the TCEQ’s experience with chemical plant MSS for NSR permits, refinery MSS for NSR permits, and oil and gas MSS and process knowledge for oil and gas registrations. The executive director staff does not have sufficient information on the physical design parameters and operational activities which occur at OGS to accurately predict other planned MSS activities with negligible emissions not listed here. To ensure an accurate list of other planned MSS emissions with negligible emissions, the commission is seeking further comment and information. If qualitative, quantitative, and/or updated information about other MSS activities with negligible emissions becomes available in the future or if emissions are found to actually be more than negligible, the TCEQ may reopen this standard permit to reevaluate other MSS activities with negligible emissions.

Proposed (i)(4) covers a very specific circumstance the commission has reviewed. This paragraph is included as an option, not a requirement, for larger OGS with multiple engine/compressor sets to authorize additional piping and material transfer to allow ongoing operations when one engine at a plant must shutdown. In these instances, the shutdown would not have an associated purging (blowdown) of VOCs, since the materials would be shifted to another part of the OGS. Start-up emissions may also occur as air is purged from the compressor with a small amount of the VOC stream. If these streams are then captured and sent to a control device with a destruction effectiveness of 95%, they are substantially minimized. If companies operate in this manner, the registration should specify all details and emission estimates.
The commission has evaluated several activities at OGS but limited information is available on others used throughout the diverse oil and gas industry and is requesting comments and technical information on activities and potential emissions. If qualitative, quantitative, and/or updated information about other MSS activities and associated emissions becomes available in the future, the commission may reopen this rule and/or the oil and gas standard permit to reevaluate other MSS activities and associated emissions.

The records, monitoring, and sampling requirements proposed in subsection (j) of the standard permit are intended to provide a clear, understandable set of expectations in order to easily establish compliance. Providing explicit requirements meets the test of practical enforceability, an essential element for all commission authorizations. Compliance with all applicable regulations is ensured through sampling (specified in Table 7 in subsection (l)), monitoring and recordkeeping (specified in Table 8 of subsection (l)). All necessary records, which include documentation of all sampling and monitoring, must be maintained and contain sufficient information to demonstrate compliance. These records are important to determine the following: verify all information used to estimate emissions; verify that emissions meet applicable limits; show current equipment and processes; explain equipment or process changes and associated effects on emissions; and show equipment is properly operated, monitored, maintained, and inspected.

Each specific sampling, monitoring, and recordkeeping requirement varies based on related effects, accurate compliance demonstrations, and protectiveness and includes the following items: a site layout including the configuration of all equipment and process units within the site must be maintained; the property line and nearest off-site receptors must be shown because impacts of pollutants are based on the property line and receptor distances; any changes to the site layout need to be recorded in case the change affects emission impacts, for example if the distance of a unit to a receptor or properly line changes; and a site process description and process flow diagram is needed to ensure that all emission points are accounted for and authorized. This documentation should clearly show all process and waste streams and the inputs and outputs of the total site and individual units or processes. Any process changes need to be recorded in case the change affects emissions. Site production or collection must be recorded over time because this is the basis for emission estimates. It is necessary to maintain records of the types of service (i.e. natural gas, oil, condensate, and water) being processed at a site in order to ensure that emission limits for each component have not been exceeded and that all constituent emissions are represented. This information is important to determine appropriate maximum acceptable emissions of all authorized facilities.

The sampling requirements are the minimum requirements customary to the applicable units. Sampling ports and platforms need only be installed when needed to obtain the samples required to demonstrate compliance. All sampling and testing including the facilities and equipment necessary to conduct the sampling are at the expense and the responsibility of the holder of the authorization. To conduct sampling, proper ports and platform access must be part of the design of the equipment vents and stacks. Basic specifications are explained in the Sampling Procedures Manual in “Chapter 2, Stack Sampling Facilities.”

Where any applicable sampling is required, for example to establish a high destruction efficiency to meet impact requirements, the testing should be conducted as soon as possible but no later than 180 days of the initial start of operation of implementation of a change which required the registration. This time frame allows for scheduling testers, coordinating limit is consistent with the Regional Office for working out process startup issues of new and modified equipment. Standard
EPA reference methods are required to be used for the sampling and analysis and they include some quality assurance and quality control procedures. Minimally, three one hour test runs should be conducted and averaged to demonstrate compliance, additional testing may be appropriate to establish different operating parameters for different operating scenarios. The TCEQ Regional Office must be provided various federal NSPS and NESHAP standards, other standard permits, typical permit conditions, as well as the proposed Level 2 confirmation of emissions. All sampling must follow the TCEQ Sampling Procedures Manual and the appropriate EPA Reference Methods to ensure consistency and quality assurance of evaluation techniques. The Regional Office shall be afforded the opportunity to observe the sampling and a minimum 30 day pre-sampling notice must be provided. The notice must include a date for a pretest meeting, the sampling date, the sampling firm, the specific equipment, methods and procedures to be used, the procedures and parameters to determine and record operating rates and parameters affecting the emissions during the sampling period, and any proposed deviations to the prescribed sampling methods so that independent audit capabilities are maintained by the commission. To allow for possible sampling observance, adjustments in sampling techniques or methods, or to provide other necessary guidance, the permit holders must contact the TCEQ when testing is scheduled, but not less than 30 days prior to sampling. Notification and opportunity for coordination with regional stack testing staff is also within the ordinary arrangements considered reasonable in stack testing requirements. After initial coordination, companies and TCEQ staff routinely work out schedules that are amenable to all parties. Following these procedures, using standard methods and communication with the Regional Office is important to avoid costly additional or retesting.

Once completed, reports should include information specified in “Chapter 14, Contents of Air Emission Test Reports” of the Sampling Procedures Manual. The report must be sent to the Regional Office within 60 days of the testing. Stack test reports submission requirements have been simplified in that one original and one copy be sent to the Regional Office. The TCEQ Regional Director is authorized to allow alternate sampling facility designs, and deviations to sampling procedures, but the authorization holder must have written approval to make the change.

Chapters 2 and 14 portions of the Sampling Procedure Manual can be found at www.tceq.state.tx.us/compliance/field_ops/acguide.html. Finally, results are required to meet National Environmental Laboratory Accreditation Conference (NELAC) certification requirements found in 30 TAC Chapter 25, Environmental Testing Laboratory Accreditation and Certification. That does not mean all data must come from a NELAC certified lab. Rather the Chapter 25 rule explains when that certification must be applied. This requirement in the standard permit is no more than what the rule requires.

Sampling of gas and liquid streams from appropriate process sampling points is required in order to determine composition or other properties needed to estimate emissions such as heat content, specific gravity, and vapor pressure. It is essential that stream lab analyses/reports include a measurement of H₂S, individual HAPs, and at least all those hydrocarbons up to at least 10 carbon atoms per molecule (C₁₀⁺). Proper quantification of emissions can only be done when information is as accurate and complete as possible. Analyses should be taken at worst case conditions in order for the results to be used to estimate the maximum possible amount of emissions. If this is not done, emission estimates may be underestimated which could result in actual emissions exceeding allowable emission limits. Records of gas and liquid analyses must be maintained and updated over time to represent current site specific information. Site specific information is needed because although one well may pull from the same formation and field as another well, formations can vary throughout and minor variations in the composition can greatly affect emissions. A representative sample can be used if the sample represents production from the same formation, field and depth. The sample should be the most conservative of the
represented sites to demonstrate worst case scenario. Samples should be taken prior to any treatment for the most accurate information for estimating emissions. If a sample is used that is from another point in the production, then the emissions will not be representative. This is due to the fact that the character and composition will be different than what is being treated. The emission prediction models will only estimate emissions based on the input parameters. If these do not match then there is no way to verify how accurate the emission estimates are. Correct parameters are needed in order to verify that the site meets the standard permit being claimed.

Petroleum formations can vary throughout and although a well may pull from the same formation and field, minor variations in the composition can greatly affect emissions. Emissions calculations should be supported with as much associated site-specific sampling and testing needed to perform such emissions calculations (e.g. a site with an outlet gas stream from a high pressure separator, outlet gas stream from a glycol unit, outlet gas stream from an amine unit, and outlet gas stream from a low pressure separator may require sampling and testing for all four gas streams to sufficiently complete emissions calculations for fugitive emission from piping components). Acceptable outputs from emissions calculations can be used in place of testing (e.g. the outlet gas flow speciation from the emission calculations output of GLYCalc 4.0 software could be used for emissions calculations for fugitive emissions from piping components). Review of available information indicates that sampling once a year is a reasonable frequency for monitoring changes to the composition of the well. Lab analysis is needed for proper quantification of emissions, specifically HAPs and H2S. As needed and required by proposed (j)(8), a pressurized gas, pressurized liquid, stock tank liquid, and stock tank vapor sample needs to be taken and analyzed. Failure to sample at the appropriate location can result in a mischaracterization and quantification of emissions.

Laboratory extended VOC Gas Chromatograph (GC) analysis at a minimum to C10+ and H2S analysis for gas and liquids for the following shall be performed and used for emission compliance demonstrations: separator at the inlet; dehydration unit prior to dehydrator; amine unit prior to sweetening unit; tanks for liquids and vapors; and produced water or brine/salt water at the inlet prior to storage.

A laboratory extended VOC GC analysis must be speciated to a minimum C10+ in order for such software programs as E&P Tanks 4.0, GRI-GlyCalc, and AmineCalc to accurately calculate emissions such as benzene, from their prospective units. For example, in order for emissions from flashing to be calculated properly with the E&P Tanks 4.0 program, a speciated analysis to C10+ along with its Molecular Weight (MW) and Specific Gravity is required. To verify the necessity for this extended analysis the E&P Tanks 4.0 program was run based on an analysis speciated out to hydrocarbons with 6 carbon atoms per molecule (C6) (representing only 35% of the needed material). The resulting uncontrolled emissions based on this analysis (normalized to reflect 100%) yielded emissions levels so high that impacts standards would not be attainable without serious control measures. Similarly, it has been determined that for sites which employ a glycol dehydration unit (where benzene emissions are of concern) to take a conservative estimate of benzene emissions would surely trigger MACT applicability. MACT applicability requires the applicant to put in place further control requirements which in the long run would be more expensive to maintain and operate than for an extended C10+ analysis to be attained. In summary, in order for an applicant to accurately represent the impacts of emissions from their respective site, a speciated analysis to C10+ must be utilized. While it is possible for an applicant to use an analysis speciated to C6, it would require the applicant to over estimate impacts from emissions such as BTEX. This over estimation could needlessly trigger federal applicability standards resulting in greater cost.
If the sampling is done at the representative worst case scenario, then worst case emissions should be represented. Historically, permitting is always based on worst-case scenarios. Sampling needs to be attained from the proper sampling locations in order to have accurate inputs for the appropriate emissions calculation methods. Sites subject to the standard permit must demonstrate how they comply with the emission limitations of H2S by obtaining an analysis of the percentage/volume of H2S of the site. In order for a site to demonstrate that they meet the requirements of the H2S emission limitations of the standard permit, one or more analysis or estimate must be obtained. The choice of analysis is the Tutwiler, Stain Tube, or full sulfur analysis. The traditional method was one analysis on the incoming site’s gas stream and to use that analysis percentage in every other stream at the site for an emission estimate. Modern computer programs and sampling have demonstrated that this method is not very inaccurate. In fact, the hydrogen sulfide concentration in the emissions to the air may increase many times from the incoming H2S liquid concentration to a tank during flash. At a minimum if no computer program is used to estimate hydrogen sulfide flash emissions at a sour site, the pressurized flash sample taken for VOC should include an H2S analysis along with the daily production rate or sampling the H2S vent concentrations from a crude oil or condensate storage tank along with the estimated VOC tank emissions should be completed to estimate H2S flash emissions. Sour sites with produced water should calculate using some basis, sample or use a computer program to estimate the produced water hydrogen sulfide emissions. It is expected that the H2S emissions be established for each facility in order to demonstrate compliance with the emission limitations. The commission continues to seek comments on H2S sampling and estimation at OGS.

Required site specific gas and liquid analysis goes together with the record requirement for equipment specifications. The volumes and pressures, material compositions of the vessels to be depressurized, purged or degassed and emptied for MSS are directly related to the emission rate estimated. The control equipment specifications from the manufacturer or design should match with the flow, temperature and pressures measured and coming process equipment for normal and, as applicable MSS, and define the appropriate compliant ranges for parameters that need to be monitored. This record explains the site operations and emissions and how they designed compliant for the worst case emission scenario.

Fugitive component monitoring and associated documentation is required because it promotes the early detection and repair of process leaks, which reduces emissions, increases safety, and can prevent product loss. Whether fugitive component monitoring encompasses BMP or LDAR program, it is necessary to maintain records of detailed fugitive component monitoring plans and practices, as well as to record LDAR program results, in order to demonstrate that fugitive emissions are being well monitored and have not exceeded applicable emission limits. These records will also justify any reductions taken on emission estimates. It is necessary to maintain records for the addition and/or replacement of piping components in order to determine how it will potentially impact fugitives and associated emissions, what additional facilities should be included in monitoring programs. Records of standardized methods or recommendations for operational specifications, maintenance schedules, BMP, and LDAR programs are necessary in order to compare with actual procedures. Records of equipment specifications are necessary inputs for emission estimates and also help confirm that equipment is operated as designed. Records of all equipment replacements and repairs are necessary to be maintained because of the effect on emissions. It is necessary to maintain records for like-kind equipment replacement especially in order to demonstrate that the replacement equipment does not significantly affect operations and emissions at the site. These records should include equipment specifications and operations and a summary of emissions (type and quantity). Site impacts should be reevaluated if there is a change.
in emissions. These records ensure that equipment is kept in good working order and corresponding emission quantifications are accurate for the OGS.

Exhaust stack sampling and testing must be performed as required for a variety of units, including engines and thermal control devices designed for and claiming high efficiency, to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere. Certain parameters may need to be monitored and recorded during the stack testing because of their effect on emission rates. Testing and quarterly performance evaluations of engines are proposed to ensure proper on-site operation of engines. On-site testing and evaluations will be needed to verify that engines are being operated within manufacturer or company-determined specifications and to ensure that public health and welfare is being protected by demonstrating that emissions from engines are not exceeding acceptable claimed or certified emissions. To provide flexibility and reduce unnecessary sampling, the commission is proposing that only 50% of identical engines must be sampled initially, with the remaining identical units sampled at the biennial timeframe with this alternating pattern continued forward. Records would need to be maintained for each engine to ensure that when an engine moves off-site, the next owner or operator has the option to follow the alternating schedule, otherwise, the engine would have to be stack sampled within 180 days of arriving at the new site. Proper on-site operation would include demonstration of compliance with health-based impacts for total VOC (as natural gas) emissions and property line standards for NOx emissions. Proper on-site operation would include demonstration that controls are operating properly, including testing for emissions of formaldehyde. However, the TCEQ is aware of significant technical hurdles to implementing a massive, state-wide sampling program for formaldehyde from oil and gas industry engines given the complexity of the approved testing methods, the time required for each test, and the availability of sampling equipment for formaldehyde. For these reasons, the TCEQ is not requiring individual engines to be tested for formaldehyde but the TCEQ intends to work with engine manufacturers to establish appropriate emission factors for specific engine models. The commission is seeking comments on formaldehyde emissions from engines. Periodic monitoring of engines is needed to ensure ongoing performance. The methods described in the proposal economical and clear indicators of these units meeting emission limitations. Engine performance can degrade over time and biennial testing is too long a period to ensure proper condition and consistent emission quantification. This proposed requirement is consistent with permit conditions, including those included in issued Existing Facility Permits for grandfathered facilities. Additionally, engine degradation can lead to increases in formaldehyde emissions. In lieu of sampling for formaldehyde, these periodic tests for CO, a qualitative indicator of good combustion, will ensure maintenance is reducing this formaldehyde increase from occurring.

For thermal oxidizers claiming efficiencies greater than 98% or establishing alternate temperature or residence time requirements, the VOC, benzene, O2 and possibly H2S exhaust content must be measured along with the exhaust temperature. Where intermediate, enhanced, or alternate monitoring requires continuous parameter monitoring standard permit averaging times and quality assurance and control checks must be applied. Averaging times of 6 minutes or less ensure that the dramatic effect of non combustion does not occur. Reasonable temperature accuracy for high temperature monitors has been ±0.75 % or ±10.55555ºF for 1,400ºF. Oxygen and CO monitoring must be zeroed and spanned daily and comply with EPA performance specifications in 40 CFR Appendix B and F. The proposed standard permit allows for an exemption from monitoring on weekends and plant holidays, and cylinder gas audits may be used in lieu of a relative accuracy test audit. Standard data availability of at least 5% is expected over rolling 12 month periods.
Condensers are generally viewed as less reliable control devices due to the potential for non-saturated emissions and variable flow conditions so sampling may be required and is mandatory for claims of efficiency over 80%. Ports and platforms should be incorporated in designs. The stack sampling requirements above would apply. Fuel records are necessary to show the amount and type of fuel used. Measuring of the fuel composition (VOC, H₂S content) may be required to ensure that emissions meet the applicable limits.

Records of unit parameter adjustments must be maintained because of the effect on emissions. Records of hours of operation, downtime of combustion devices, and engines, as measured by run time meters or other process monitors, are necessary to ensure that equipment is operating properly and corresponds to emission quantifications. Any redirection of vent streams during operational variations must be recorded and must explain associated alternate controls and emission releases to the atmosphere. This is important to ensure that emissions from these alternate operations do not exceed the applicable emission limits.

Tank/process vessel records must be maintained to ensure that the tanks are properly inspected and maintained to reduce and minimize potential increases in emissions due to poor tank condition and non-reflective paint color.

Truck loading records of amount and type of material being loaded must be maintained as well as the type of transfer used. This is important for demonstrating the site outputs and estimating emissions. Tank truck certificates and testing records must be maintained to ensure that loading emissions were estimated appropriately including the proper use of reductions taken based on controls.

Cooling tower and heat exchanger systems records on circulation and solids define potential emissions. Emission estimates of VOC applying uncontrolled factors from AP-42, Compilation of Air Pollutant Emission Factors, are generally accepted to account for losses until process losses are noticed. Emission estimates using controlled factors from AP-42 are generally accepted when the water circulating back to the cooling tower is routinely monitored so heat exchangers leaks can be detected and repaired sooner. The cooling water return to the cooling tower must be monitored for VOC emissions by the method in Appendix P, of the Sampling Procedures Manual or equivalent approved in writing specific to the site to ensure that VOC emissions meet the applicable emission limits when the control factor is assumed. The VOC faulty equipment trigger of 0.08 ppmv in the water are standard in permits and associated with the capability of the Appendix P method and associated AP-42 controlled emission factor in Texas. Particulate emissions from cooling towers are associated with the solids content and drift from the tower. Permit holders are assumed to be regulating and maintaining a designed maximum solid content through water blowdowns and makeup water so the heat exchangers and piping do not lose process effectiveness from scale and plugging. Where blowdown is necessary to maintain solids content the record of the weekly total dissolved solids is required. Drift eliminators should be inspected annually to maintain the design control estimated.

MSS records including the source and control of blowdowns and depressurization must be maintained in order to demonstrate that emissions are protective of public health and do not exceed the hourly and annual limitations for the site. There is a potential for a large amount of emissions in a short period of time with these types of events.

Flares and vapor combustors designed like flares, all pilot flames must be continuously monitored by a thermocouple or an infrared monitor to ensure the presence of a flame, which is essential for
gas ignition. Any loss in pilot flame must be recorded in order to properly account for resulting uncontrolled emissions.

Thermal oxidizer exhaust temperature and a method of establishing hours of operation are the basic monitored parameters. For higher efficiency design and claim continuous temperature recording and compliance and where claimed oxygen or carbon monoxide concentration must be continuously monitored and recorded when waste gas is directed to it to ensure good combustion/waste gas destruction. Flexibility is allowed when utilizing waste gas for fuel in process combustion devices as noted previously and six minute averages address the dramatic effect (0 % control) of non-combustion. Quality assurance, quality control, and all necessary maintenance should be recorded.

Some of the proposed records may already be compiled and kept in various formats for other regulatory agencies. The commission is seeking comment and is continuing research on this issue.

Proposed subsection (k) is proposed to outline requirements for establishing site-specific emission limits based on one or more standardized impacts evaluation techniques. Proposed (k)(1) includes a basic precept for all air permitting emission quantifications, that estimates be based on representative, worst-case operations and planned MSS activities. Proposed (k)(2) discusses how and from what distances measured from facilities and nearby property lines or receptors so there is no confusion during evaluation and implementation.

Proposed subsection (k)(3) discusses emission considerations, such as: the most appropriate character of VOC to evaluate; formaldehyde is only expected from engines; that the analysis must not show an exceedance of an ambient air standard or ESL; and that if emissions for any specific contaminant are below specified values, no additional review is needed. These values were developed from the generic impact tables, conservative and appropriate dispersion characteristics, at the closest distance (50 feet). If emissions are less than these values, all ambient air standards and ESLs will be met and requiring an analysis by applicants would be redundant and unnecessary. The value for NOx is based on the less than 1,000 hp engine table, the new hourly NAAQS, and the shortest stack height, or 9 lb/hr. The value for H2S is based on the fugitive column of Table 2 at 50 feet and is 0.025 lb/hr. The value for SO2 is based on the 10 foot height process vent column of Table 2 at 50 feet and is 0.42 lb/hr. Since the stream going to the amine reboiler is an extremely concentrated sour gas stream, emissions from this process vent can have extremely high SO2 emissions. All sites that have emissions over 0.4 lb/hr will have to demonstrate protectiveness. The value for benzene is based on the fugitive column of Table 2 at 50 feet. Since the annual ESL for benzene is more stringent than the hourly ESL, the commission assumed steady-state releases of benzene and estimated maximum hourly emissions using the annual ESL, resulting in a value of 0.013 lb/hr. The value for toluene is based on the fugitive column of Table 2 at 50 feet and is 0.146 lb/hr. The value for xylene is based on the fugitive column of Table 2 at 50 feet and is 0.08 lb/hr.

Finally, in proposed (k)(4), the commission proposes three methods for demonstrating protectiveness: tables developed from generic impacts modeling performed by the commission; screening modeling; or refined dispersion modeling. The commission proposes to limit the evaluation in subsection (k) to 2,700 feet based on consideration of distance limits for contiguous properties and operationally related facilities; the highly conservative nature of the model and modeling approach discussed in the Protectiveness Review section; and the commission’s intent to establish conservative emission rates and site-wide caps to address the requirements of various air quality permitting programs. In addition, it is the commission’s experience that worst-case
modeled concentrations from the facilities authorized by this rule do not occur under actual operating and meteorological conditions and are not measured at the values predicted at distances beyond 2700 feet.

Proposed (k)(4)(A) outlines the simplest approach to this evaluation, the generic impacts modeling tables developed by the commission. Based on the variability of equipment and operations, it was determined that emission releases would be grouped for dispersion modeling to predict acceptable off-property impacts. This analysis will be compared to expected emission types and quantities for assessment of protectiveness and compliance with state and federal emission standards from common OGS. The generic approach could also be used to show the appropriate insignificance or acceptability of various operations, providing additional flexibility for OGS seeking authorization under the standard permit. The groups of similar emission releases were chosen based on similar parameters of the release points.

Table 1 lists the equations which give the maximum acceptable emissions when using the tables. This equation is similar to \( E = L/K \) in §106.262, but with different parameters. For ambient air standards, \( E_{\text{max}} = P/G \) where \( E_{\text{max}} \) is the maximum hourly emissions acceptable (lb/hr); \( P \) is the appropriate property line standard (\( \mu g/ m^3 \)); and \( G \) is the value from the Generic Emissions Tables at the emission point’s release height and distance to property line ([\( \mu g/m^3 \])/[lb/hr]). For health effects review, \( E_{\text{max}} = ESL/G \) where \( E_{\text{max}} \) is the maximum acceptable hourly emissions (lb/hr); ESL is the current published effects screening level for the specific air contaminant (\( \mu g/m^3 \)); and \( G \) is the value from the Generic Emissions Tables at the emission point’s release height and distance to property line ([\( \mu g/m^3 \])/[lb/hr]).

Most OGS have more than one facility or release point of emissions. To account for this variability, instead of co-locating all sources at the most conservative point of release to establish acceptable emission rates and confirm compliance with the proposed standard permit, OGS may use a weighted fraction method. The five tables predict impacts based on various dispersion characteristics, with greater acceptable emissions from various sources (smallest to largest): fugitives, blowdowns, process vents, combustion devices, and flares. Since many of these facilities emit air contaminants simultaneously, the corresponding contribution of each release must be considered to ensure acceptable emissions. Therefore, acceptable emission limits are determined using a weighed ratio. For simultaneously emitting sources, the weighted fraction method with the above equation may be used for any combination of sources emitting the same air contaminant: 

\[
E_{\text{max}} (\text{lb/hr}) = (WR \text{ EPN 1}) (P / G \text{ EPN 1}) + (WR \text{ EPN 2}) (P / G \text{ EPN 2}) + (WR \text{ EPN 3}) (P / G \text{ EPN 3}) +\ldots \text{or } E_{\text{max}} (\text{lb/hr}) = (WR \text{ EPN 1}) (ESL /G \text{ EPN 1}) + (WR \text{ EPN 2}) (ESL/G \text{ EPN 2}) + (WR \text{ EPN 3}) (ESL/G \text{ EPN 3}) +\ldots
\]

With minor adjustments, this same equation can be used for annual impacts evaluation. Standard practice, as published in the TCEQ Modeling Guidance Document, is to multiply the hourly impact concentration by 0.08 to establish a conservative annual impact concentration. Thus, the weighted fraction equations would be: 

\[
E_{\text{max}} (\text{tpy}) = (8760/2000) \{ (WR \text{ EPN 1}) (P / [0.08*G \text{ EPN 1}]) + (WR \text{ EPN 2}) (P / [0.08*G \text{ EPN 2}]) + (WR \text{ EPN 3}) (P / [0.08*G \text{ EPN 3}]) +\ldots \text{or } E_{\text{max}} (\text{tpy}) = (8760/2000) \{ (WR \text{ EPN 1}) (ESL /[0.08*G \text{ EPN 1}]) + (WR \text{ EPN 2}) (ESL/[0.08*G \text{ EPN 2}]) + \}
\]

where \( E_{\text{max}} (\text{lb/hr}) = \) maximum hourly emissions acceptable (lb/hr); \( E_{\text{max}} (\text{tpy}) = \) maximum tons per year emissions acceptable (tpy); \( WR \text{ EPN}(x) = \) Emissions of each EPN divided by the sum of total emissions for all EPNs that emit that pollutant or (EEPN x/Etotal); \( P = \) short term or annual (as appropriate) property line standard (\( \mu g/m^3 \)); \( ESL = \) current published short term or annual (as appropriate) effects screening level for the specific air contaminant (\( \mu g/m^3 \)); and \( G = \) value from the Generic Emissions Tables at the emission point’s release height and distance to property line.
Based on modeling guidance, a pressurized vessel and other facilities which release emissions in an undirected manner and short duration such as pressurized separators, sulfur treating vessels, piping, and tanks, etc. can be treated as a fugitive released emission covered in this standard permit. These emissions should be reviewed under the first column for “fugitive, loading, and tanks” in Table 2. For federal purposes, this definition of “fugitive” is not appropriate since these emissions are potentially collectable and capable of being routed to a control. This difference in accounting for these emissions for federal purposes could be significant in a few application situations near significant and major increase levels in PSD applications, since for named major sources fugitive emissions count in PSD evaluation of the emissions. For other federal sources, fugitive emissions are not counted in determination of a significant or major emission increase.

The cumulative impacts from any given OGS as defined must be considered for protectiveness. To provide flexibility, applicants may use the weight fraction method of proportioning impacts in the same way as §§106.261 and 106.262 currently use to proportion impacts from different sources at different distances. The proposed authorizations will contain several tables applicable to the type sources located at the site. This will enable an applicant to compute their emission limits for the applicable air contaminants from those sources. Each table will allow an applicant to either meet specific emission limits, or compute the specific emission limit for that type source. These tables can be used assuming 100% of the specific emissions are at a worst-case point (very conservative). They may also be used to compute the specific emission limit for each emission point (may involve different distances, heights, and type tables) by use of the weight fraction method, which will allow for consideration of multiple, similarly emitting sources operating simultaneously at an OGS. The most conservative approach using the worst-case source calculated from each table will result in the maximum impact allowed for protectiveness from that source without regard to other sources emitting the same compound at the same time. Using the weight fraction approach, emission limits can be established for all other type equipment emitting the same compound at the same time. If the OGSS estimated emission rates using either method are less than or equal to the calculated emission rate limit as determined from the tables, the emissions are acceptable and can be authorized.

Proposed subsection (k)(4)(B) includes a screening alternative based on the use of the SCREEN3 model. The OGS would follow a modeling protocol provided by the commission to conduct a modeling analysis that demonstrated acceptable emissions from the site. The protocol and associated guidance would be included in an oil and gas guidance document available via the agency website and is summarized in this document. The protocol would be followed exactly and there would be no opportunity to modify the protocol on a case-by-case basis. However, the commission could modify the modeling protocol and guidance to resolve technical issues or clarify instructions, or allow the use of other screening models. Since this is a standardized approach, it is appropriate to allow OGS to use these mechanisms to demonstrate protectiveness. The commission contemplates a protocol similar to as described below.

For control options, the following parameters must be chosen: the regulatory default option must be selected; the flat terrain choice should be used; and rural or urban dispersion options may be used based on the land use in the vicinity of the sources to be permitted. A land use analysis must be conducted to determine the majority land-use type within 3 kilometers (km) of the sources to be permitted. The goal in a land-use analysis is to estimate the percentage of the area within a 3-km radius of the source to be evaluated as either urban or rural. If the land-use designation is clear (about 70 percent or more of the total land-use is either urban or rural), then no further refinement
is required and the model should be run with the appropriate land-use designation. If the land-use
designation is not clear, the model should be run twice, once with each option and the higher of
the two predicted concentrations should be reported.

For source options in the screen model, only point sources, pseudo-point sources, and flares are
applicable to represent emission sources. If the emission sources cannot be represented by one of
the source types, then this method cannot be used. The point source parameters shall include the
following: emission rate (g/s); stack height (m); stack inside diameter (m); stack gas exit velocity
(m/s) or flow rate (ft³/min or m³/s); and stack gas temperature (K). For fugitive sources and for
any sources that do not release to the atmosphere through standard stacks (such as stacks or vents
with rain caps, horizontal releases), use the pseudo-point characterization with the following
modeling parameters: stack exit velocity = 0.001 meter per second; stack exit diameter = 0.001
meter; stack exit temperature = 0 Kelvin; and actual release height. Flares shall include: emission
rate (g/s); flare stack height; and total heat release rate (cal/s). SCREEN3 assumes an effective
stack gas exit velocity (ν_e) of 20 m/s and an effective stack gas exit temperature (T_s) of 1273K,
and calculates an effective stack diameter based on the heat release rate. Enclosed vapor
combustion units should not be modeled with the preceding parameters but instead with stack
parameters that reflect the physical characteristics of the unit.

The starting receptor should be located at the shortest distance from the facility/source to the
property line. The ending receptor should be far enough away to ensure that the model can predict
a GLCmax between the two points. For meteorology, the model default of full meteorology is
required, the model default of 10 meters is required for the anemometer height, and the model
default of regulatory is required for the mixing height. Downwash is not applicable for the
purposes of this modeling demonstration. If downwash is required, then this method cannot be
used.

The output shall include: the maximum predicted concentration must be used to compare against
the applicable ESL, NAAQS, or state ambient air standard; and the following conversion factors
can be used to convert 1-hour concentrations from SCREEN3 to averaging times greater than 1-
hour: 3-hour multiply by 0.9; 8-hour multiply by 0.7; 24-hour multiply by 0.4; quarterly multiply
by 0.2; and annual multiply by 0.08. The following steps must be followed when conducting the
NAAQS analysis: model all new and modified sources, or the project; compare the maximum
predicted concentration from the project to the appropriate de minimis level - compliance with the
NAAQS is demonstrated if the maximum predicted concentration from the project is less than or
equal to the de minimis level; a site wide analysis must be conducted for project results than de
minimis; model the allowable emission rate of all sources on site that emit the regulated pollutant;
and add a background concentration to the maximum predicted site wide concentration and
compare the total concentration to the NAAQS. Compliance with the NAAQS is demonstrated if
the total concentration is less than NAAQS. The following steps must be followed when
conducting the analysis to show compliance with the state standards for net ground-level
concentrations in 30 TAC Chapter 112: model all new and modified sources-- the project;
compare the maximum predicted concentration from the project to the appropriate de minimis
level - compliance with the state property line standards is demonstrated if the maximum predicted
concentration from the project is less than or equal to the de minimis level; if the maximum
predicted concentration is greater than de minimis, a site wide analysis must be conducted; model
the allowable emission rate of all sources on site that emit the regulated pollutant; and compliance
with the state property line standard is demonstrated if the maximum predicted site-wide
concentration is less than or equal to the state property line standard.
There are two recommended methods of screening techniques. These are the worst-case stack method and the multiple source method. The worst-case stack method selects the single worse case stack for the site and assumes that all pollutants will be emitted from that point. The worst-case stack method allows all pollutants to be evaluated from a single stack. Use the following equation to determine the worst-case stack: 

\[ M = \frac{(h_s V T_s)}{Q} \]

where 

- \( M \) = a parameter that accounts for the relative influence of stack height, plume rise, and emission rate on concentrations;
- \( h_s \) = the physical stack height in meters;
- \( V \) = \( \frac{\pi}{4} d^2 \) = the stack gas flow rate in cubic meters per second;
- \( \pi \) = pi;
- \( d \) = inside stack diameter in meters;
- \( v_s \) = stack gas exit velocity in meters per second;
- \( T_s \) = the stack gas exit temperature in Kelvin;
- \( Q \) = pollutant emission rate in grams per second.

The stack with the lowest value of \( M \) is considered to be the worst-case stack. The multiple source method allows each source to be modeled at 1 lb/hr. The unit impact for each source is multiplied by the pollutant specific emission rate to calculate a maximum predicted concentration for each pollutant. The maximum predicted concentration for each source is summed to get a total concentration for each pollutant. This technique works best if the unit impacts and emission rates for each source and each pollutant are loaded into a spreadsheet such as Microsoft EXCEL. Once the modeling exercise is complete the results should be summarized in a modeling report. The modeling report should be sent to the TCEQ and include a compact disk (CD) with all modeling input files, output files, plot plan, and all other files of supporting information used in the modeling demonstration.

Proposed subsection (k)(4)(C) includes a refined dispersion modeling alternative based on the Industrial Source Complex model. The OGS would follow a modeling protocol provided by the commission to conduct a modeling analysis that demonstrated acceptable emission from the site. The protocol and associated guidance would be included in an oil and gas guidance document available via the agency website. The protocol would be followed exactly and there would be no opportunity to modify the protocol on a case-by-case basis. However, the commission could modify the modeling protocol and guidance to resolve technical issues, clarify instructions, or allow the use of other refined dispersion models. Since this is a standardized approach, it is appropriate to allow OGS to use these mechanisms to demonstrate protectiveness.

The control options used must meet the following: the regulatory default option must be selected; the flat terrain choice should be used; plume depletion options are not allowed; and rural or urban dispersion options may be used based on the land use in the vicinity of the sources to be permitted. A land use analysis must be conducted to determine the majority land-use type within 3-km of the sources to be permitted. The goal in a land-use analysis is to estimate the percentage of the area within a 3-km radius of the source to be evaluated as either urban or rural. If the land-use designation is clear (about 70 percent or more of the total land-use is either urban or rural), then no further refinement is required and the model should be run with the appropriate land-use designation. If the land-use designation is not clear, the model should be run twice, once with each option and the higher of the two predicted concentrations should be reported. The commission contemplates a protocol similar as that described below.

Only point sources, pseudo-point sources, and flares are applicable to represent emission sources. If the emission sources cannot be represented by one of the source types, then this method cannot be used. Point source parameters shall meet the following: emission rate (g/s); stack height (m); stack inside diameter (m); stack gas exit velocity (m/s) or flow rate (ft³/min or m³/s); and stack gas temperature (K). For fugitive sources and for any sources that do not release to the atmosphere through standard stacks (such as stacks or vents with rain caps, horizontal releases), use the pseudo-point characterization with the following modeling parameters: stack exit velocity = 0.001 meter per second; stack exit diameter = 0.001 meter; stack exit temperature = 0 Kelvin; and actual
release height. For flares, the following must be included: emission rate (g/s); effective stack exit velocity = 20 meters per second; effective stack exit temperature = 1273 Kelvin; actual height of the flare tip; and effective stack exit diameter. The effective stack diameter (D) in meters is calculated using the following equations: 

\[ D = \sqrt{10^{-6} q_n} \]  

and 

\[ q_n = q(1 - 0.048 \sqrt{MW}) \]  

where: 

- \( q \) = gross heat release in cal/sec; 
- \( q_n \) = net heat release in cal/sec; and 
- \( MW \) = weighted (by volume) average molecular weight of the compound being flared. Enclosed vapor combustion units should not be modeled with the preceding parameters but instead with stack parameters that reflect the physical characteristics of the unit.

The following sets of receptor spacing shall be used to locate the maximum predicted concentration. The maximum predicted concentration should not be located at the edge of the receptor grid. If the maximum predicted concentration occurs within 1,000 meters of the property line, the medium and coarse receptors would not need to be included in the analysis: tight receptors - receptors spaced 25 meters apart extending out to a distance of 300 meters from the property line; fine receptors - receptors spaced 100 meters apart beginning at 300 meters from the property line and extending out to a distance of 1,000 meters from the property line; medium receptors - receptors spaced 500 meters apart beginning at 1,000 meters from the property line and extending out to a distance of extending out to a distance of 5,000 meters. The Air Dispersion Modeling Team (ADMT) has prepared meteorological data sets for state modeling analyses. These data sets are available for download from the ADMT Internet page. The ADMT prepared meteorological data sets must be used in the modeling analysis and may be found at [http://www.tceq.state.tx.us/permitting/air/modeling/admtmet.html](http://www.tceq.state.tx.us/permitting/air/modeling/admtmet.html). The required year for short term modeling is 1988 (1989 for counties using Shreveport data). The actual anemometer height must be used for each airport location. Anemometer heights may be found at [http://www.tceq.state.tx.us/assets/public/permitting/air/memos/anemom96.pdf](http://www.tceq.state.tx.us/assets/public/permitting/air/memos/anemom96.pdf).

Downwash is not applicable for the purposes of this modeling demonstration. If downwash is required, then this method cannot be used. For the coordinate system: enter receptor locations and source locations into dispersion models in universal transverse mercator (UTM) coordinates, in order to be consistent with on-property emission point locations represented in the Table 1(a) contained in the permit application, plot plan, and other reference material, such as United States Geological Survey topographic maps; UTM coordinates in datum NAD27 or NAD83 must be used. When representing receptor and source locations in UTM coordinates, applicants must make certain that all of the coordinates originated in, or are converted to, the same horizontal datum. Applicable UTM zones in Texas are either 13 (from the west border to 102 degrees longitude), 14 (between 102 and 96 degrees longitude), or 15 (east of 96 degrees longitude to the east border); and coordinate systems based on plant coordinates, applicant-developed coordinate systems, or polar grids will not be accepted.

The output must include: the maximum predicted concentration must be used to compare against the applicable ESL, NAAQS, or state ambient air standard; and the use of any other concentration rank (high second high, high sixth high) will not be accepted. The following steps must be followed when conducting the analysis: model all new and modified sources -- the project; compare the maximum predicted concentration from the project to the appropriate de minimis level - compliance with the NAAQS is demonstrated if the maximum predicted concentration from the project is less than or equal to the de minimis level; a site-wide analysis must be conducted for project results other than de minimis; model the allowable emission rate of all sources on site that emit the regulated pollutant; and add a background concentration to the maximum predicted site wide concentration and compare the total concentration to the NAAQS. Compliance with the NAAQS is demonstrated if the total concentration is less than NAAQS. The following steps must
be followed when conducting the analysis to show compliance with the state standards for net ground-level concentrations in 30 TAC Chapter 112: model all new and modified sources-- the project; compare the maximum predicted concentration from the project to the appropriate de minimis level - compliance with the state property line standards is demonstrated if the maximum predicted concentration from the project is less than or equal to the de minimis level; if the maximum predicted concentration is greater than de minimis, a site wide analysis must be conducted; model the allowable emission rate of all sources on site that emit the regulated pollutant; and compliance with the state property line standard is demonstrated if the maximum predicted site-wide concentration is less than or equal to the state property line standard. Once the modeling exercise is complete, the results should be summarized in a modeling report. The modeling report should be sent to the TCEQ and include a CD with all modeling input files, plot files, output files, plot plan, and all other files of supporting information used in the modeling demonstration.

Proposed subsection (l) contains all the Tables associated with the proposed standard permit:

- Table 1 Emission Impact Tables Limits and Descriptions;
- Table 2 Generic Modeling Results for Fugitives & Process Vents;
- Table 3 Generic Modeling Results for Engines and Turbines Less than or equal to 1000 hp;
- Table 4 Generic Modeling Results for Engines and Turbines Greater Than 1000 hp;
- Table 5 Generic Modeling Results for Flares;
- Table 6 Generic Modeling Results for Blowdowns & Gas Pipeline Purging;
- Table 7 Sampling and Demonstrations of Compliance;
- Table 8 Monitoring and Records Demonstrations;
- Table 9 Engine and Turbine Emission and Operational Standards;
- Table 10 Fugitive Component LDAR BACT Table;
- Table 11 Best Available Control Technology Requirements; and
- Table 12 Control Device Requirements

**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 $1200 per sample. Sites may require 1 to 6 samples yearly depending on the facilities installed. This gives a potential cost range of $800 to $7,200. The new standard permit 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 oil and gas sites. This estimate is based on facilities having emissions of volatile organic compound below 5 tpy and sulfur compounds below 0.1 tpy. Those facilities not affected by new control requirements are only responsible for notification to the executive director.

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 oil and gas sites 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 volatile organic compounds (VOCs) from engines. This would be expected to increase the total cost of testing for engines and turbines from about $2000 per test for VOC 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 dollars for current testing (NOx and 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 oil and gas site 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 dollars. 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 NOx and CO for boilers, reboilers, heater-treaters, and process heaters, less than 40 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 NOx 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 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 oil and gas sites is $50,000 to $100,000 per engine.

Engines will have to do a quarterly photo ionization detector (PID) test which is about $1000 per test, due to the SIP engines in DFW 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.

VI. PUBLIC NOTICE AND COMMENT PERIOD

In accordance with 30 TAC §116.603, Public Participation in Issuance of Standard Permits, the TCEQ will publish notice of the proposed standard permit in the Texas Register and newspapers of the largest general circulation in the following metropolitan areas: Austin, Dallas, Houston, Midland/Odessa, Tyler, Brownsville, and Amarillo. The date of these publications will be August 11, 2010. The public comment period will end on September 17, 2010. Any person is entitled to submit comments regarding the proposed standard permit.

Copies of the proposed Air Quality Standard Permit for Oil and Gas Sites may be obtained from the TCEQ Web site at http://www.tceq.state.tx.us/permitting/air/nav/standard.html or by contacting the Texas Commission on Environmental Quality, Office of Permitting and Registration, Air Permits Division, at (512) 239-1250. Comments may be mailed to Ms. Anne Inman, Texas Commission on Environmental Quality, Office of Permitting and Registration, Air Permits Division, MC 163, P.O. Box 13087, Austin, Texas 78711-3087 or faxed to (512) 239-2101. All comments should reference the standard permit for Oil and Gas Production Facilities. Comments must be received by 5:00 p.m. on September 17, 2010. To inquire about the submittal of comments or for further information, contact Ms. Inman at (512) 239-1276. Si desea información en Español, puede llamar al (800) 687-4040.
XXI. PUBLIC MEETING

The TCEQ will hold a public meeting on the proposed standard permit for oil and gas sites on September 14, 2010 at 10:00 a.m., at the Texas Commission on Environmental Quality, Bldg. E, Room 201S, 12100 Park 35 Circle, Austin. The meeting will be 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 with the audience will not occur during the meeting; however, TCEQ staff will be available to discuss the standard permit 30 minutes prior to the meeting and staff will also answer questions after the meeting.

Persons who have special communication or other accommodation needs who are planning to attend the public meeting should contact the TCEQ at (512) 239-1495. Requests should be made as far in advance as possible.

XXII. STATUTORY AUTHORITY

This standard permit is proposed under Texas Health and Safety Code, the Texas Clean Air Act (TCAA), §382.011, General Powers and Duties, which authorizes the commission to control the quality of the state's air, THSC §382.051, Permitting Authority of Commission; Rules, which authorizes the commission to issue permits, including standard permits for similar facilities, and TCAA §382.0513, Permit Conditions, which authorizes the commission to establish and enforce permit conditions consistent with the TCAA, and TCAA §382.05195, Standard Permit, which authorizes the commission to issue standard permits according to the procedures set out in that section.
PROPOSED AIR QUALITY STANDARD PERMIT FOR OIL AND GAS SITES

(a) **Applicability.** This standard permit applies to all stationary facilities, or groups of facilities, at a site which handle gases and liquids associated with the production, conditioning, processing, and pipeline transfer of fluids or gases found in geologic formations on or beneath the earth’s surface including, but not limited to, crude oil, natural gas, condensate, and produced water. The following restrictions apply:

(1) Only one Oil and Gas Sites Standard Permit may be registered for each site and authorizes all facilities in sweet or sour service. This standard permit may not be used if operationally related facilities are authorized by the permit by rule for Oil and Gas Sites under Title 30 Texas Administrative Code (30 TAC) §106.352, Oil and Gas Sites, or a permit under 30 TAC §116.111, General Application. Other facilities which are not covered under this standard permit may be authorized by other authorizations at an oil and gas site if (b)(6) of this standard permit is met.

(2) This standard permit does not relieve the owner or operator from complying with any other applicable provision of the Texas Health and Safety Code, Texas Water Code, rules of the Texas Commission on Environmental Quality (TCEQ), or any additional local, state or federal regulations. Emissions that exceed the limits in this standard permit are not authorized and are violations of the standard permit.

(3) Emissions from upsets, emergencies, or malfunctions are not authorized by this standard permit. This standard permit does not regulate methane, ethane, or carbon dioxide.

(b) **Definitions and Scope.**

(1) Facility is a discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a stationary source. Stationary sources associated with a mine, quarry, or well test lasting less than 72 hours are not considered facilities.

(2) Receptor includes any building which is in use as a single or multi-family residence, school, or place of worship at the time this standard permit is registered. A residence is a structure primarily used as a permanent dwelling. This term does not include structures occupied or used solely by the owner or operator of the oil and gas facility, or the mineral rights owner of the property upon which the facility is located. All measurements of distance to receptors shall be taken from the emission release point at the oil and gas facility that is nearest to the point on the building that is nearest to the oil and gas facility.

(3) Oil and Gas Site (OGS) is defined as all facilities which meet the following:
   (A) Located on contiguous or adjacent properties;
   (B) Under common interest and control; and
   (C) Designated under same 2-digit standard industrial classification (SIC) codes.

(4) For purposes of determining applicability of 30 TAC § 122, Federal Operating Permits, the definitions of §122.10, General Definitions, apply.
(5) For purposes of registration under this standard permit, the following must be met:

(A) Any new facility or new group of related facilities at an OGS, or changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit or increase emissions to amounts greater than previously registered, must meet all requirements of this standard permit prior to construction or implementation of changes.

(B) Existing authorized facilities, or group of facilities, at an OGS under this standard permit which are not changing previously registered character or quantity of emissions must only meet (b)(6) and (i) of this standard permit until the registration is renewed after December 31, 2015.

(C) A single standard permit registration shall include all facilities or groups of facilities at an OGS which are directly operationally related to each other and are located no greater than a 1/4 mile from the facilities associated with a project requiring registration under this standard permit. If piping or fugitive components are the only connection between facilities that may otherwise be operationally separated, the piping and fugitive components will not be considered when determining the 1/4 mile separation for registration.

(D) All facilities at an OGS registered under this standard permit must be in compliance with emission character and quantity representations of any registration under this standard permit or previous versions of this standard permit.

(E) Planned maintenance, startup, and shutdowns (MSS) information is not required to be registered if no other changes are occurring. An addendum to the OGS standard permit registration may be filed using Form APD-CERT by hard-copy or the E-permits system. Planned MSS information sufficient to demonstrate compliance with this standard permit shall be incorporated at the next amendment or renewal to the standard permit registration after January 5, 2012.

(6) This standard permit supersedes the emissions limits of 30 TAC §116.610(a)(1), Applicability. For purposes of ensuring protection of public health and welfare and demonstrating compliance with applicable ambient air standards and effects screening levels the following must be met:

(A) At an OGS, all facilities, regardless of authorization type, located within ¼ mile of a project requiring registration under this standard permit shall be evaluated, including fugitive components. If a claim under this standard permit is only for planned MSS under subsection (i), the analysis shall evaluate planned MSS only.

(B) Hourly and annual emissions shall be limited based on the most stringent of subsections (h) or (k) of this standard permit. Compliance with ambient air standards shall be demonstrated for any property-line within 2,700 feet of a project under this standard permit for the following air contaminants: nitrogen oxides (NOx), sulfur dioxide (SO2), and hydrogen sulfide (H2S) unless otherwise listed in subsection (k). Compliance with hourly and annual effects screening levels (ESL) for benzene, toluene, and xylene shall be demonstrated at the nearest receptor within 2,700 feet of a project under this standard permit unless otherwise listed in subsection (k).
(C) If control or recovery units are necessary to meet the limitations of this subsection, the devices must meet the specifications and requirements of Table 12.

(c) **Authorized Facilities, Changes and Activities.**

(1) For existing OGS which are authorized by previous versions of this standard permit:

(A) Addition of new facilities, or changes to existing facilities which increase the potential to emit, or any increase in emissions over previous representations, requires registration in accordance with (b)(5) of this standard permit unless otherwise specified.

(B) Addition of any piping, fugitive components, any other new facilities, or changes to existing facilities that increase the OGS potential to emit or registered emissions less than or equal to 1.0 tpy volatile organic compounds (VOC), 5 tpy NOx, 0.01 tpy benzene, and 0.05 tpy H2S, or addition of any new engine rated less than 100 hp, over a rolling 12 month period, does not require registration if the following are also met:

(i) Total increases over any period of time must be \( \leq 5 \text{ tpy VOC or NOx, 0.05 tpy benzene, or 0.1 tpy H}_2\text{S} \), or a registration or registration update under this standard permit is required.

(ii) New facilities and changes to existing facilities must not otherwise increase the potential to emit or increase emissions of other facilities at the OGS over previous representations.

(iii) The fugitive components or other new facilities must meet the applicable requirements of subsection (e) and (j).

(iv) These facilities and changes shall be incorporated at the next revision or update to a registration under this standard permit.

(C) Replacement of any facility is authorized, does not require registration, and must meet only the applicable requirements of subsection (e) of this standard permit if all of the following are met:

(i) The replacement facility does not increase the previously registered emissions or potential to emit of the facilities at the OGS;

(ii) Replacement facility information shall be incorporated at the next revision or update to a registration under this standard permit; and

(iii) Only if facilities or groups of facilities are changed in such a way as to increase the potential to emit, production processing capacity, or registered emission rate, the BACT Tables listed in subsection (l) of this standard permit are required to be met prior to any renewal before December 31, 2015.

(D) In lieu of registering proposed changes under this standard permit, incremental emissions increases associated with construction of new facilities or changes to existing facilities may be authorized by 30 TAC §106.261, Facilities (Emission Limitations) or §106.262, Facilities (Emissions and Distance Limitations), if the maximum worst-case
emissions also meet the limitations established by subsections (b)(6) and (k) of this standard permit for all air contaminants with proposed increases.

(E) The authorization to operate under the standard permit must be renewed in accordance with 30 TAC §116.604, Duration and Renewal of Registrations to Use Standard Permits. As of January 1, 2016, upon renewal, the owner or operator of a facility will be required to be in compliance with all requirements of this standard permit as required by 30 TAC §116.605, Standard Permit Amendment and Revocation.

(2) All registrations under this standard permit shall meet the following:

(A) New, changed, or replacement facilities shall not exceed the thresholds for major source or major modification as defined in 30 TAC §116.12, Nonattainment and Prevention of Significant Deterioration Review Definitions, and in Federal Clean Air Act §112(g) or §112(j);

(B) All facilities shall comply with all applicable Title 40, Code of Federal Regulations (40 CFR) Parts 60, 61, and 63 requirements for New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT); and

(C) All facilities shall comply with all applicable requirements of Chapters 111, Control of Air Pollution from Visible Emissions and Particulate Matter, 112 Control of Air Pollution from Sulfur Compounds, 113 Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants, 115 Control of Air Pollution from Volatile Organic Compounds, and 117 Control of Air Pollution from Nitrogen Compounds.

(3) All facilities related to the operation of any OGS, under any version of this standard permit (or co-located at a site with an OGS standard permit), previously authorized by, and continuing to meet the conditions of a permit by rule under 30 TAC Chapter 106, Permits by Rule (or any historical version), or as specified in (d)(2) of this standard permit must:

(A) Be incorporated into this standard permit in any initial registration, revision, or renewal for this standard permit. These facilities will become authorized by this standard permit and previous authorizations will be voided.

(B) Meet all emission limits established by this standard permit and review in accordance with subsection (b)(6).

(C) Meet requirements of subsections (e), (i), and (j) for Best Management Practices and Minimum Requirements, Planned MSS, and associated Records, Sampling and Monitoring of this standard permit.

(D) Only if facilities or groups of facilities are changed in such a way as to increase the potential to emit, production processing capacity, or registered emission rate, the BACT Tables listed in subsection (l) of this standard permit are required to be met.
The executive director shall perform a compliance history review in accordance with 30 TAC Chapter 60. The executive director may not issue a registration under this standard permit if an applicant is a poor performer. In addition, the executive director may deny an application for registration under this standard permit for good cause.

(d) **Facilities and Exclusions**

(1) Only the following specific facilities and groups of facilities have been evaluated for this standard permit, along with supporting infrastructure equipment and facilities, and may be included in a registration:

(A) Fugitive components, including valves, pipe flanges and connectors, seals, instrumentation, and associated piping;

(B) Pumps and meters;

(C) Separators, including gun barrels, free-water knockouts, oil/water, and membrane units;

(D) Condensers;

(E) Treatment and Processing, including heater-treaters, methanol injection, glycol dehydrators, molecular or mole sieves, amine sweeteners, SulfaTreat®, and iron sponge units;

(F) Cooling Towers;

(G) Gas Recovery units, including cryogenic expansion, absorption, adsorption, heat exchangers and refrigeration units;

(H) Combustion units, including engines, turbines, boilers, reboilers, heaters and heater-treaters;

(I) Storage tanks for crude oil, condensate, produced water, pressure tanks with liquid petroleum liquids, fuels, treatment chemicals, and slop and sump oils;

(J) Underground storage of gas or liquids and associated surface support facilities;

(K) Truck loading equipment;

(L) Control equipment including vapor recovery systems, condensers, flares, vapor combustors, and thermal oxidizers; and

(M) Temporary facilities used for planned maintenance and temporary control devices for planned start-ups and shutdowns.

(2) **Exclusions.** The following are not authorized under this standard permit:

(A) Sour water strippers or sulfur recovery units;

(B) Carbon dioxide hot carbonate processing units;
(C) Water injection facilities (these facilities may otherwise be authorized by 30 TAC §106.351, Salt Water Disposal);

(D) Liquefied Petroleum Gases (LPG), crude oil, or condensate transfer or loading into or from railcars, ships, or barges (these facilities may otherwise be authorized by §§106.261 and 106.262);

(E) Incinerators for solid waste destruction;

(F) Remediation of petroleum contaminated water and soil (these facilities may otherwise be authorized by §106.533, Remediation;

(G) Cooling Towers and heat exchangers with direct contact with gaseous or liquid process streams containing VOC, H₂S, halogens or halogen compounds, cyanide compounds, inorganic acids, or acid gases; and

(H) Any emission increases in an Air Pollutant Watch List area for one or more applicable Air Pollutant Watch List contaminants designated for that area.

(e) **Best Management Practices (BMP) and Minimum Requirements.** For any new facility, group of new facilities, or changes to existing facilities which increase the potential to emit or any increase in emissions over previous representations, and any associated emission control equipment at an OGS registered under this standard permit, the following shall be met as applicable:

(1) All facilities which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations. Each site shall establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order. The minimum requirements of this program shall include:

   (A) Manufacturer’s specifications and recommended programs applicable to equipment performance and effect on emissions;

   (B) Cleaning and inspection of all equipment; and

   (C) Replacement and repair of equipment on schedules which prevent equipment failures and maintain performance;

(2) Planned downtime of any capture, recovery or control device must be considered when evaluating emission limitations of this standard permit, and if needed, gas streams shall be redirected to another control or recovery device during downtime.

(3) Any OGS facility shall be operated at least fifty (50) feet from any property-line or receptor whichever is closer to the facility. This distance limitation does not apply to the following:

   (A) Any valve that is used for isolation and or safety purposes can only consist of fugitive components, and must be at least 25 feet from any receptor as required for the easement
(B) Any OGS facility at a location for which the distance requirements were satisfied at
the time this standard permit is registered (provided that the authorization was
maintained) regardless of whether a receptor is subsequently built or put to use fifty
(50) feet from any OGS facility; or

(C) Existing, immovable, fixed OGS facilities which were constructed and previously
authorized, even if modified.

(f) **General Requirements** All facilities under this standard permit shall meet the following
specifications, design, and control requirements, and:

(1) All new facilities or new activities authorized by this standard permit shall meet the design,
capture or emission control requirements as listed on Tables 9-12 as listed in subsection (l) of
this standard permit.

(2) Engines and turbines shall meet the following:

   (A) The emission and performance standards listed in Table 9.

   (B) Documentation of the engine’s manufactured date and type (spark or compression
ignition, lean or rich burn), horsepower rating, and any previous emission sampling
results summary must be included in the registration;

   (C) Diesel fueled engines used for back-up power generation and periodic power needed at
the OGS are authorized if the fuel has no more than 0.05% sulfur and is operated less
than 500 hours per rolling 12-month period. Fuel for all other internal combustion
engines (ICE) shall be sweet gas or liquid petroleum gas unless the engine is lean burn
and rated under 500 hp in which case sour gas is allowed;

   (D) Engines and turbines used for electric generation more than 876 hours per rolling 12-
month period are authorized if no electric grid access is available and Table 9 is met. In
all other circumstances, electric generators must meet the technical requirements of the
Air Quality Standard Permit for Electric Generating Unit (EGU) (not including the
EGU registration requirements);

   (E) All applicable requirements of 30 TAC Chapter 117; and

   (F) All applicable requirements of 40 CFR Parts 60 63, relating to NSPS, NESHAPs, and
MACT.

(3) All seals and gaskets in VOC or H₂S service shall be installed, checked, and properly
maintained to prevent leaking. New and replaced fugitive components and instrumentation in
gas or liquid service with the uncontrolled potential to emit equal to or greater than 10 tpy
VOC or 1 tpy H₂S are subject to a leak detection and repair (LDAR) program as specified in
Table 10. Additional requirements are applicable where uncontrolled potential to emit equal
to or greater than 25 tpy VOC or 5 tpy H₂S as specified in Table 10. Planned MSS from
fugitive components must also meet the requirements of Table 10.

(4) All process equipment and storage facilities individually must meet the requirements of Table
11. Any combination of process equipment and storage facilities with an uncontrolled PTE of
equal to or greater than 25 tpy of VOC must also meet the requirements of Table 11, row titled “Combined Control Requirements”. All of the following streams and facilities must be included for this site-wide assessment:

(A) For any gaseous vent stream with a concentration of 1% VOC must be considered for capture and control requirements;

(B) For any liquid stream with a potential to emit of equal to or greater than 1 tpy VOC for each vessel or storage facility.

(5) All control devices must meet the requirements of Table 12.

(g) Registration

(1) This standard permit supersedes the notification requirements of 30 TAC §116.615, General Conditions. Any claim under this standard permit must comply with all applicable requirements of 30 TAC §116.610; §116.611, Registration to Use a Standard Permit; §116.614, Standard Permit Fees; and §116.615, General Conditions. All registrations, registration revisions, and renewals shall be submitted to the commission through a PI-1S Standard Permit Registration Form. Fee requirements do not apply when there are changes in representations with no increase in emissions within 6-months after a standard permit registration has been issued.

(2) Except as allowed by (c)(1)(B), the following shall be met:

(A) Construction of new facilities shall not begin until written confirmation is issued by the commission;

(B) Changes or modifications to existing authorized facilities, which have the potential to increase emissions or change the character of emissions, require registration no later than 30 days after the change is implemented.

(3) This registration shall include a detailed summary of maximum emissions estimates based on: site-specific gas and liquid analysis; equipment design specifications and operations; material type and throughput; and other actual parameters essential for accuracy.

(4) If the registration is for a new site, or new facilities at an existing site, emission estimates shall be updated and recorded for site- or facility-specific data within 180 days from start of operation or implemented changes. If the results show an increase in registered emissions, a revised registration must be submitted for review, including a fee.

(h) Emission Limitations. The OGS must have the potential of less than the following emissions after any recovery or controls. If control or recovery units are necessary to meet the limitations of this subsection, the devices must meet the specifications and requirements of Table 12.

(1) Total VOCs are limited to 200 lb/hr and 250 tpy, and include the following:

(A) 20 lb/hr and 10 tpy benzene;

(B) 35 lb/hr toluene and 10 tpy toluene;
(C) 19 lb/hr xylene and 10 tpy xylene; and

(D) 3 lb/hr and 10 tpy formaldehyde.

(2) Sulfur compounds are limited to the following:

(A) 6 lb/hr and 15 tpy H₂S; and

(B) 12 lb/hr and 50 tpy SO₂.

(3) Products of combustion are limited to the following:

(A) 53 lb/hr and 250 tpy NOₓ;

(B) 57 lb/hr and 250 tpy CO; and

(C) 4 tpy PM₁₀/PM₂.₅.

(i) Planned Maintenance, Start-ups and Shutdowns (MSS). For any facility, group of facilities or site using this standard permit or previous versions of this standard permit, the following shall apply:

(1) Prior to January 5, 2012, representations and registration of planned MSS is voluntary, but if represented must meet the applicable limits of this standard permit. After January 5, 2012, all emissions from planned MSS activities and facilities must be considered for compliance with applicable limits of this standard permit. This standard permit may not be used at a site or for facilities authorized under §116.111 if planned MSS has already been authorized under that permit.

(2) As specified, releases of air contaminants during, or as result of, planned MSS must be quantified and meet the emission limits in this standard permit, as applicable. This analysis must include:

(A) Alternate operational scenarios or redirection of vent streams;

(B) Pigging, purging, and blowdowns;

(C) Temporary facilities meeting §106.263(e), Routine Maintenance, Start-up and Shutdown of Facilities and Temporary Maintenance Facilities, if used for degassing or purging of tanks, vessels, or other facilities;

(D) Degassing or purging of tanks, vessels, or other facilities;

(E) Management of sludge from pits, ponds, sumps, and water conveyances;

(F) Amine and other treatment chemicals replacement (except glycols);

(G) Hot oil treatments.

(3) Other planned MSS activities authorized by this standard permit are limited to the following.
These planned MSS activities require only recordkeeping:

(A) Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance;

(B) Boiler refractory replacements and cleanings;

(C) Heater and heat exchanger cleanings;

(D) Cleaning of separator, amine, and dehydrator dump valves (does not include depressurization losses);

(E) Amine filter replacements;

(F) Turbine hot section swaps;

(G) Pressure relief valve testing, calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens; and

(H) After any necessary degassing and purging, which must be addressed in (i)(2) above, pump, compressor, heat exchanger, vessel, water treatment systems (cooling, boiler, potable), and fugitive component maintenance.

(4) Engine/compressor set start-ups associated with preventative system shutdown activities have the option to be authorized as part of typical operations for an OGS if:

(A) Prior to operation, alternative operating scenarios to divert gas or liquid streams are registered with all supporting documentation;

(B) Engine/compressor shutdowns shall not result in emissions; and

(C) Emissions which result from the subsequent compressor start-up activities are controlled to a minimum of 98% efficiency for VOC and H₂S.

(j) Records, Sampling and Monitoring. The following records shall be maintained at a site in written or electronic form and be readily available to the agency or local air pollution control program with jurisdiction upon request. All required records must be kept at the facility site. If however, the facility normally operates unattended, records must be maintained at an office within Texas having day-to-day operational control of the plant site.

(1) Sampling and demonstrations of compliance shall include the requirements listed in Table 7 in subsection (l).

(2) Monitoring and records for demonstrations of compliance shall include the requirements listed in Table 8 in subsection (l).

(k) Emission Limits Based on Impacts Evaluation.

(1) All emissions estimates must be based on representative worst-case operations and planned
MSS activities.

(2) Distance measurements shall be determined using the following:

(A) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest receptor must be used with the appropriate compliance determination method with the published ESLs as found through the current list at on the commissioner’s website.

(B) For each facility or group of facilities, the shortest corresponding distance from any emission point, vent, or fugitive component to the nearest property line must be used with the appropriate compliance determination method with any applicable state and federal ambient air quality standard.

(3) Evaluation of emissions shall meet the following:

(A) The most appropriate character of VOC must be used for each emission release point at the site. If all applicable VOCs are not evaluated, the most restrictive ESL, most conservative dispersion parameters, closest distance, and lowest release heights shall be used to determine maximum acceptable emissions. For all evaluations of NOx to NO2 a conversion factor of at least 0.75 may be used or other factors as otherwise specified in a modeling protocol provided to the commission.

(B) The maximum predicted concentration or rate must not exceed a state or federal ambient air standard or ESL. A site-wide analysis including all on-property sources should be conducted. This demonstration must use the maximum predicted concentration to compare to the applicable short- and long-term standards or ESL. If the total quantity of emissions are less than the following rates, no additional analysis or demonstration of the specified air contaminant is required:

(i) 9 lb/hr NOx;
(ii) 0.025 lb/hr H2S;
(iii) 0.42 lb/hr SO2;
(iv) 0.013 lb/hr benzene;
(v) 0.08 lb/hr xylene; and
(vi) 0.146 lb/hr toluene.

(4) Evaluation must comply with one of the methods listed with no changes or exceptions:

(A) Tables. Tables 1-6 in subsection (l) of this standard permit where:

(1) Emission impact tables may be used in accordance with the limits and descriptions in Table 1.

(2) Values in Tables 2-6 may be used with linear interpolation between height and
distance points; however a distance of less than 50 feet or greater than 2,700 feet may not be used. If distances and release heights are not interpolated, the next lowest height and lesser distances shall be used for determination of maximum acceptable emissions. All facilities exempted from the distance to the property line restriction in (f)(1) must use 50 feet as the distance to the property line for those ambient standards based on property line.

(B) **Screening Modeling.** A screening model may be used to demonstrate acceptable emissions from an OGS under this standard permit if all of the parameters in the screening modeling protocol provided by the commission are met.

(C) **Dispersion Modeling.** A refined dispersion model may be used to demonstrate acceptable emissions from an OGS under this standard permit if all of the parameters in the refined dispersion modeling protocol provided by the commission are met.

(I) The following Tables shall be used as required by this standard permit.

- Table 1 Emission Impact Tables Limits and Descriptions;
- Table 2 Generic Modeling Results for Fugitives & Process Vents;
- Table 3 Generic Modeling Results for Engines and Turbines Less than or equal to 1000 hp;
- Table 4 Generic Modeling Results for Engines and Turbines Greater Than 1000 hp;
- Table 5 Generic Modeling Results for Flares;
- Table 6 Generic Modeling Results for Blowdowns & Gas Pipeline Purging;
- Table 7 Sampling and Demonstrations of Compliance;
- Table 8 Monitoring and Records Demonstrations;
- Table 9 Engine and Turbine Emission and Operational Standards;
- Table 10 Fugitive Component LDAR BACT Table;
- Table 11 Best Available Control Technology Requirements; and
- Table 12 Control Device Requirements.
### Table 1 Emission Impact Tables Limits and Descriptions

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<thead>
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<th>Variables</th>
<th>Description</th>
<th>Details</th>
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</tr>
<tr>
<td>E&lt;sub&gt;MAX&lt;/sub&gt; ANNUAL</td>
<td>the maximum acceptable annual (tpy) emissions</td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>ambient air standard (µg/m&lt;sup&gt;3&lt;/sup&gt;)</td>
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<tr>
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<td>current published effects screening level for the specific air contaminant</td>
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<td>G</td>
<td>the most stringent of any applicable generic value from the Tables at the</td>
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<td>WR EPN(x)≡</td>
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<td>64</td>
<td>74</td>
<td>70</td>
</tr>
</tbody>
</table>
### Table 7 Sampling and Demonstrations of Compliance

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
<th>Specifications and Expectations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sampling General</td>
<td>When Applicable Ports &amp; Platforms, Methods, Notifications and Timing</td>
<td>(A) If necessary, sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in &quot;Chapter 2, Stack Sampling Facilities.&quot; Engines and other facilities which are physically incapable of having platforms are excluded from this requirement. For control devices with effectiveness requirements only, appropriate sampling ports shall also be installed upstream of the inlet to control devices or controlled recovery systems with control efficiency requirements. Alternate sampling facility designs may be submitted for written approval by the TCEQ Regional Director or his designee. (B) Where stack testing is required, Sampling shall be conducted within 180 days of the change that required the registration, in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods. Sampling shall occur as three one-hour test runs and then averaged to demonstrate compliance with the limits of this standard permit. Any deviations from those procedures must be approved in writing by the TCEQ Regional Director or his designee prior to sampling. (C) The Regional Office shall be afforded the opportunity to observe all such sampling. (D) The holder of this authorization is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. (E) The TCEQ Regional Office that has jurisdiction over the site shall be contacted as soon as any testing is scheduled, but not less than 30 days prior to sampling. The region shall have discretion to amend the 30 day prior notification. Except for engine testing and liquid/gas analysis sampling, all other sampling shall include an opportunity for the appropriate regional office to schedule a pretest meeting. The notice shall include: (i) Date for pretest meeting, if required; (ii) Date sampling will occur; (iii) Name of firm conducting sampling; (iv) Type of sampling equipment to be used; (v) Method or procedure to be used in sampling; (vi) Procedure used to determine operating rates or other relevant parameters during the sampling period; (vii) parameters to be documented during the sampling event; (viii) any proposed deviations to the prescribed sampling methods. If held, the purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. (F) Within 60 days after the completion of the testing and sampling required herein, one original and one copy of the sampling reports shall be sent to the Regional Office. (G) When sampling is required, all QA/QC shall follow 30 TAC Ch 25 NELAC accreditation requirements.</td>
</tr>
<tr>
<td>LDAR</td>
<td>testing of the new and reworked piping connections</td>
<td>Gas or hydraulic testing at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 8 hours of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance.</td>
</tr>
<tr>
<td>LDAR</td>
<td>Analyzers</td>
<td>An approved gas analyzer or other approved detection monitoring device used for the VOC fugitive inspection and repair requirement is a device that conforms to the requirements listed in Title 40 CFR §60.485(a) and (b), or is otherwise approved by the EPA as a device to monitor for VOC fugitive emission leaks. Approved gas analyzers shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured. In lieu of using a hydrocarbon gas analyzer and EPA Method 21, the owner or operator may use the Alternative Work Practice in 40 Code of Federal Regulations Part 60, §60.18(g) - (i). The optical gas imaging instrument must meet all requirements specified in 40 CFR §60.18(g) - (i).</td>
</tr>
<tr>
<td>Verify composition of materials</td>
<td>All site-specific gas or liquid analyses</td>
<td>Reports necessary to verify composition (including H₂S) at any point in the process. All analyses shall be representative of the site. All analysis shall be performed within 180 days of initial start of operation or implementation of a change which requires registration. When new streams are added to the site and the character or composition of the streams change and cause an increase in authorized emissions, or upon request of the appropriate Regional office or local air pollution control program with jurisdiction, a new analysis will need to be performed.</td>
</tr>
</tbody>
</table>
### Engines & Turbines

<table>
<thead>
<tr>
<th>Initial Sampling of</th>
<th>Engine or turbine</th>
</tr>
</thead>
<tbody>
<tr>
<td>(i) Any engine greater than 500 horsepower;</td>
<td>Perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere (including but not limited to NOx, CO, VOC, and O2). Each combustion facility shall be tested at a minimum of 50% of the design maximum firing rate of the facility. Each tested firing rate shall be identified in the sampling report. Sampling shall occur within 180 days after initial start-up of each unit. Additional sampling shall occur as requested by the TCEQ Regional Director. If there are multiple engines at an OGS of identical model, year, and control system, sampling may be performed on 50% of the units and used for compliance demonstration of all identical units at the OGS. The remaining 50% if the units not initially tested must be tested during the next biennial testing period. This sampling is not required upon initial installation at any location if the engine or turbine was previously installed and tested at any location in the USA and the test performed conformed with EPA Reference Methods. Regardless of engine location, records of performance testing, or relied upon sampling reports, must remain with each specific engine for a minimum of 5 years.</td>
</tr>
<tr>
<td>(ii) Any turbine</td>
<td></td>
</tr>
</tbody>
</table>

### Engines

<table>
<thead>
<tr>
<th>Periodic Evaluation</th>
</tr>
</thead>
<tbody>
<tr>
<td>(A) Conduct evaluations of each engine performance every calendar quarter after initial compliance testing by measuring the NOx, CO, and O2 content of the exhaust. Test shall occur more than 30 days apart. Individual engines shall be subject to quarterly performance evaluation if they were in operation for 500 hours or more during the three-month (quarterly) period. The performance of each engine shall be evaluated at a minimum once per year regardless of hours of operation. (B) The use of portable analyzers specifically designed for measuring the concentration of each contaminant in parts per million by volume is acceptable for these evaluations. The portable analyzer shall be operated in accordance with the EPA’s, Office of Air Quality Planning and Standards, Emission Measurement Center Conditional Test Method - Determination of O2, CO, and NOx from Stationary Sources for Periodic Monitoring (Portable Electrochemical Analyzer Procedure) [CTM-034] (September 8, 1999) or any equivalent method as promulgated through 40 CFR Part 60 or Part 63. The NOx and CO emissions then shall be converted into units of grams per horsepower-hour and pounds per hour. (C) Emissions shall be measured and recorded in the as-found operating condition, except no compliance determination shall be established during start-up, shutdown, or under breakdown conditions. After each occurrence of engine maintenance such as major component replacement, overhaul, oxygen sensor replacement, or catalyst replacement, an evaluation of engine performance as described above shall be performed within two weeks. (D) In lieu of the above mentioned periodic monitoring for engines and biennial testing, the holder of this permit may install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to measure and record the concentrations of NOx, NO, and CO from any engine, turbine, or other external combustion facility. Diluents to be measured include O2 or CO2. Except for system breakdowns, repairs, calibration checks, zero and span adjustments, and other quality assurance tests, the CEMS shall be in continuous operation and shall record a minimum of four, and normally 60, approximately equally spaced data points for each full hour. The NOx and diluents CEMS shall be operated according to the methods and procedures as set out in 40 CFR Part 60, Appendix B, Performance Specifications 2 and 3. The CO CEMS shall be operated according to the methods and procedures as set out in 40 CFR Part 60, Appendix B, Performance Specifications 4, 4A, or 4B. CEMS shall follow the quality assurance requirements of Appendix F except that Cylinder Gas Audits may be conducted in all four calendar quarters in lieu of the annual Relative Accuracy Test Audit. A CEMS with downtime due to breakdown or repair of more than 10% of the facility operating time for any calendar shall be considered as a defective CEMS and the CEMS shall be replaced within 2 weeks.</td>
</tr>
<tr>
<td>Combustion Devices</td>
</tr>
<tr>
<td>---</td>
</tr>
<tr>
<td>Oxidation or Combustion Control Device</td>
</tr>
<tr>
<td>Condensers</td>
</tr>
</tbody>
</table>
### Table 8 Monitoring and Records Demonstrations

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
<th>Record Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site Production or Collection</td>
<td>natural gas, oil, condensate, and water production records</td>
<td>Site inlet and outlet gas volume and sulfur concentration, daily gas/liquid production and load-out from tanks</td>
</tr>
<tr>
<td>Equipment and facility summary</td>
<td>Current process description</td>
<td>As-built plot plan with property line, off-site receptors, and all equipment on-site</td>
</tr>
<tr>
<td>Equipment specification</td>
<td>Process units, tanks &amp; equipment, vapor recovery units; flares; thermal oxidizers; and reboiler control devices (glycol, amine unit)</td>
<td>Volumes and pressures, material and compositions of process vessels to be depressurized, purged or degassed and emptied for MSS, demonstrations that the control equipment is properly sized to handle the volumes, pressures, flows and/or emissions processed or controlled, and the manufacturer’s or design engineers estimate of appropriate compliant ranges for parameters that need to be monitored.</td>
</tr>
<tr>
<td>Site LDAR Program</td>
<td>Details of fugitive component monitoring plan, and LDAR results, including QA, QC</td>
<td>(A) A monitoring program plan must be maintained that contains, at a minimum, the following information: (i) an accounting of all the fugitive components by type and service at the site with the total uncontrolled fugitive potential to emit estimate; (ii) identification of the components at the site that are required to be monitored with an instrument or are exempt with the justification, note the following can be used for this purpose: (a) piping and instrumentation diagram (PID); or (b) a written or electronic database; (iii) the monitoring schedule for each component at the site with difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), identified and justified, note if an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times and a record of the plan to monitor shall be maintained; and (iv) the monitoring method that will be used (audio, visual, or olfactory means; Method 21; the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (v) for components where instrument monitoring is used, information clarifying the adequacy of the instrument response; (vi) the plan for hydraulic or pressure testing or instrument monitoring new and reworked components. (B) Records must be maintained of all monitoring instrument calibrations. (C) Records must be maintained for all monitoring and inspection data collected for each component required to be monitored with a Method 21 portable analyzer that include the type of component and the monitoring results in ppmv regardless if the screening value is above or below the leak definition. (D) Leaking components must be tagged and a leaking-components monitoring log must be maintained for all leaks greater than the applicable leak definition (i.e. 10,000 ppmv, 2000 ppmv, or 500 ppmv) of VOC detected using Method 21, all leaks detected by AVO inspection, and all leaks found using Alternative Work Practice specified in 40 CFR §60.18(i). The log must contain, at a minimum, the following: (i) the method used to monitor the leaking component (audio, visual, or olfactory inspection; Method 21; or the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (ii) the name of the process unit or other appropriate identifier where the component is located; (iii) the type (e.g., valve or seal) and tag identification of component; (iv) the results of the monitoring (in ppmv if a Method 21 portable analyzer was used); (v) the date the leaking component was discovered; (vi) the date that a first attempt at repair was made to a leaking component; (vii) the date that a leaking component is repaired; (viii) the date and instrument reading of the recheck procedure after a leaking component is repaired; and (ix) the leaks that cannot be repaired until turnaround and the date that the leaking component is placed on the shutdown list. (E) If the owner or operator is using the Alternative Work Practice specified in 40 CFR §60.18(i), the records required by 40 CFR §60.18(i)(4). (F) Any open-ended line or valve which is a repair or replacement not completed within 72 hours shall be monitored on a weekly basis except that a leak is defined as any VOC reading greater than background. The results of this weekly check and any corrective actions taken shall be recorded. (G) Audio, visual and olfactory inspections shall occur quarterly for BMP and at least weekly in concert with required instrument monitoring programs by operating personnel walk-through and be recorded. (H) A check of the reading for any pressure-sensing device to verify rupture disc integrity shall be performed weekly.</td>
</tr>
<tr>
<td>Minor Changes</td>
<td>Additions, changes or replacement of components or facilities</td>
<td>Records showing all replacements and additions, including summary of emission type and quantities.</td>
</tr>
<tr>
<td>---------------</td>
<td>---------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Equipment Replacement</td>
<td>Like-Kind replacement</td>
<td>Records on equipment specifications and operations, including summary of emissions type and quantity.</td>
</tr>
<tr>
<td>Process Units</td>
<td>Glycol Dehydration Units</td>
<td>Records of Operational Monitoring and Testing Records (Glycol Solution, Contact Pressure, Temperature, and Pump Rate)</td>
</tr>
<tr>
<td>Process Separators</td>
<td></td>
<td>Records of Operational Monitoring and Testing Records (Worst Case Pressure)</td>
</tr>
<tr>
<td>Oil/Water Separators</td>
<td></td>
<td>Records of Operational Monitoring and Testing Records (Worst Case Temperature) Note, weekly check of floating cover where applicable.</td>
</tr>
<tr>
<td>Amine Units</td>
<td></td>
<td>Records of Operational Monitoring and Testing Records (Amine Solution, Contact Pressure, Temperature and Pump Rate)</td>
</tr>
<tr>
<td>Boilers, Reboilers, Heater-Treaters, and Process Heaters</td>
<td>Combustion</td>
<td>Records of Operational Monitoring and Testing Records Records of the hours of operation of every combustion device and engines of any size by the use of a process monitor such as a run time meter. The owner or operator may choose to undergo testing and retesting at the most frequent intervals identified in Table 7 in lieu of installing a process monitor and recording the hours of operation</td>
</tr>
<tr>
<td>Internal Combustion Engines</td>
<td>Combustion</td>
<td>Records of Appropriate Operational Monitoring and Testing Records Records of the hours of operation of every combustion device and engines of any size by the use of a process monitor such as a run time meter. The owner or operator may choose to undergo testing and retesting at the most frequent intervals identified in Table 7 in lieu of installing a process monitor and recording the hours of operation See fuel records below</td>
</tr>
<tr>
<td>Gas Fired Turbines</td>
<td>Combustion</td>
<td>Records of Appropriate Operational Monitoring and Testing Records Records of the hours of operation of every combustion device and engines of any size by the use of a process monitor such as a run time meter. The owner or operator may choose to undergo testing and retesting at the most frequent intervals identified in Table 7 in lieu of installing a process monitor and recording the hours of operation</td>
</tr>
<tr>
<td>Fuel Records</td>
<td>VOC and Sulfur Content</td>
<td>For each separate fuel gas use at the site, the fuel usage and VOC content if the VOC content was used in emission estimation. If field gas contains more than 1.5 grains (24 ppmv) of H2S or 30 grains total sulfur compounds per 100 dscf, the operator shall maintain records, including at least quarterly measurements of fuel H2S and total sulfur content, which demonstrate that the annual SO2 emissions do not exceed limitations</td>
</tr>
<tr>
<td>Tanks/Vessels</td>
<td>Color/Exterior</td>
<td>Records demonstrating inspection and maintenance of paint color and vessel integrity.</td>
</tr>
<tr>
<td>Storage Tanks Loading</td>
<td>Each Loading Spot Emission and emission potential</td>
<td>Maintain a record of the material that can be stored in each tank and the maximum vapor pressure used to establish the maximum potential short term emission rate for the loading.</td>
</tr>
<tr>
<td>Truck Loading</td>
<td>All Types</td>
<td>Records indicating what was loaded, what the amount transferred is, how long it took to transfer the material, and whether loading was splash, bottom or submerged.</td>
</tr>
<tr>
<td>Vacuum Trucks</td>
<td></td>
<td>Note loading with an air mover or vacuum with the basic record. No additional record note is needed where a vacuum truck uses only an on-board or portable pump to push material into the truck.</td>
</tr>
<tr>
<td>Controlled Loading</td>
<td></td>
<td>Where controlled loading is required note the connection to the control that was employed with the basic record.</td>
</tr>
<tr>
<td>Tank Truck Certification</td>
<td></td>
<td>Records of tank truck certifications and testing.</td>
</tr>
</tbody>
</table>
### Cooling Tower Design Data

Records shall be kept of maximum cooling water circulation rate and basis, maximum total dissolved solids allowed as maintained through blowdown, and towers design drift rate. These records are only required if the cooling system is used to cool process VOC streams or control from drift eliminators or minimizing solids content is needed to meet particulate matter emission limits.

### VOC Leak Monitoring, Maintenance and Repair

Cooling tower heat exchanger systems cooling process VOC streams are assumed to have potential uncontrolled leaks repaired when obviated by process problems. If controlled emissions (systems monitored for leaks) are required to meet emission rate limits then the cooling tower water shall be monitored monthly for VOC leakage from heat exchangers in accordance with the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or another air stripping method approved by the TCEQ Executive Director. Cooling water VOC concentrations above 0.08 ppmw indicate faulty equipment. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. Faulty equipment shall be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs. Records must be maintained of all monitoring data and equipment repairs.

### Particulate Monitoring, Maintenance and Repair

Inspect and note integrity of drift eliminators annually, repairing as necessary. If a maximum solids content must be maintained through blow-down to meet particulate emission rate limits, cooling water shall be sampled once a week for total dissolved solids (TDS), monthly at unattended sites, maintaining records of the monitoring results and all corrective actions.

### Alternate Planned MSS or other Operational Variations

Records of redirection of vent streams during primary operational unit or control downtime, including associated alternate controls, releases and compliance with emission limitations.

### Planned MSS Degassing and Cleaning Process Vessels and Equipment, directly and indirectly related to the production of natural gas and natural gas liquids

Records of the source and control where applicable of blowdowns or depressurization. Documentation shall be maintained of the locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the purge gases. If the process equipment is purged with a gas, two system volumes of purge gas must pass through the control device or controlled recovery system. In addition, keep records of:

- (A) Type of activity;
- (B) Time and duration of activity;
- (C) Reason and root cause for activity;
- (D) Control of activity;
- (E) Composition of emissions released;
- (F) Estimated emissions released; and
- (G) Plant processes and procedures to prepare and execute planned and unplanned MSS.

### Planned MSS Records

Records or copies of work orders, contracts, or billing by contractors for the following activities shall be kept at the site, or nearest manned site, and made available upon request:

- Alternate operational scenarios or redirection of vent streams;
- Pigging, purging, and blowdowns;
- Temporary facilities meeting §106.263(e) of this title (relating to Routine Maintenance, Start-up and Shutdown of Facilities and Temporary Maintenance Facilities) if used for degassing or purging of tanks, vessels, or other facilities;
- Degassing or purging of tanks, vessels, or other facilities;
- Management of sludge from pits, ponds, sumps, and water conveyances;
- Amine and other treatment chemicals replacement (except glycols);
- Hot oil treatments.
- Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance;
- Boiler refractory replacements and cleanings;
- Heater and heat exchanger cleanings;
- Cleaning of separator, amine, and dehydrator dump valves;
- Amine filter replacements;
- Turbine hot section swaps;
- Pressure relief valve testing, calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens.
## Control Devices

### Flare Monitoring
Flare monitoring requires the flare and pilot flame to be continuously monitored by a thermocouple or an infrared monitor. Where an automatic ignition system is employed, the system shall ensure ignition when waste gas is present. The time, date, and duration of any loss of flare or pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer’s specifications. A temporary, portable or backup flare used less than 480 hours per year is not required to be monitored. Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated.

### Oxidation and Combustion Device Performance Monitoring
- **Basic**
  - Basic monitoring is a thermocouple or infrared monitor that indicates the device is working.
  - Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated.

- **Intermediate**
  - Intermediate monitoring and records include continuously monitoring and recording temperature to insure the control device is working when waste gas can be directed to the device and showing compliance with the 1400 F if applicable.

- **Enhanced**
  - Enhanced monitoring requires continuous temperature and oxygen or carbon monoxide monitoring on the exhaust with six minute averages recorded to show compliance with the temperature requirement and the design oxygen range or a CO limit of 100 ppmv. Some indication of waste gas flow to the control device, like a differential pressure, flow monitoring or valve position indicator, must also be continuously recorded, if the flow to the control device can be intermittent.

- **Alternate Monitoring**
  - Records of stack testing and the monitored parameters during the testing shall be maintained to allow alternate monitoring parameters and limits.

### Condensers
Continuous monitoring and recording of the temperature of the waste gas exhaust. Enhanced monitoring includes records of the stack testing and monitoring and records of the appropriate temperature and flow conditions to assure the enhanced efficiency claim as determined by the testing.

### Vapor Capture and Recovery
Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated. Appropriate monitoring includes: Records demonstrating the unit is designed and installed as a single or two-stage unit; operating pressure and temperature of the separator dumping the oil to the tank and the pressure within the tank; Oil composition and API gravity; Tank operating characteristics (e.g., sales flow rate, size of tank); and ambient temperature; (said information can be demonstrated through the use of the E&P Tanks 2.0 program.)

### Control with process combustion or heating devices (e.g. reboilers, heaters & furnaces)
Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated. The following are effective and can include monitors for: a fire box temperature, rising or steady process temperature, CO, primary fuel flow, fire box pressure or equivalent. Enhanced monitoring is required for greater control and partial operational claims. These must include the following monitors: continuous fire box, fire box exhaust temperature, CO and O2 monitoring, with at least 6 minute averages recorded. Additionally, enhanced monitoring where the waste gas may be flowing when the control device is not firing must show continuous disposition of the waste gas streams, including continuous monitoring of flow or valve position through any potential by-pass to the control.

## Monitoring
When monitoring is required, all QA/QC shall follow 30 TAC Ch 25 NELAC accreditation requirements.
Table 9 Engine and Turbine Emission and Operational Standards

<table>
<thead>
<tr>
<th>Engine Type</th>
<th>Engine Size</th>
<th>Manufacture Date</th>
<th>NOx (g/bhp-hr)</th>
<th>CO (g/bhp-hr)</th>
<th>VOC (g/bhp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rich Burn</td>
<td>less than 100 hp</td>
<td>All dates</td>
<td>no standard</td>
<td>no standard</td>
<td>no standard</td>
</tr>
<tr>
<td></td>
<td>greater than or</td>
<td>Before January 1, 2011</td>
<td>2</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>equal to 100 hp</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>greater than or</td>
<td>After January 1, 2011</td>
<td>1</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>equal to 100 hp</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| After January 1, 2015 and regardless of manufacture date, no rich burn engine greater than or equal to 100 hp authorized by this permit shall emit NOx in excess of 0.5 g/bhp-hr. If an engine becomes authorized by this permit after January 1, 2015, the permit holder shall have one year from the date of authorization to comply with a limit of 0.5 g/bhp-hr for NOx. This one year grace period follows the engine when it leaves the site if the engine also is authorized under this permit at the new site. The commission reserves the right to re-evaluate the upgrade requirement if EPA promulgates any standards for existing engines.

| Lean Burn, 2SLB     | less than 500 hp     | All dates              | no standard    | no standard   | no standard   |
|                     | greater than or     | Before September 23, 1982 | 8             | 3             | no standard   |
|                     | equal to 500 hp      | Before June 18, 1992 and rated less | 8              | 3             | no standard   |
|                     |                      | than 825 hp            |                |               |               |
|                     |                      | After September 23, 1982, but prior to June 18, 1992 and rated 825 hp or greater | 5             | 3             | no standard   |
|                     |                      | After June 18, 1992 but prior to July 1, 2010 | 2.0 except under reduced speed, 80-100% of full torque conditions may be 5.0 | 3             | no standard   |
|                     |                      | On or after July 1, 2010 | 1              | 3             | 1             |

| Lean Burn, 4SLB     | less than 500 hp     | Before July 1, 2008    | no standard    | no standard   | no standard   |
|                     | greater than or     | On or after July 1, 2008 | 2              | 3             | 1             |
|                     | equal to 500 hp      | Before September 23, 1982 | 5.0 except under reduced speed, 80-100% of full torque conditions may be 8.0 | 3             | no standard   |
|                     |                      | Before June 18, 1992 and rated less than 825 hp | 5.0 except under reduced speed, 80-100% of full torque conditions may be 8.0 | 3             | no standard   |
|                     |                      | After September 23, 1982, but prior to June 18, 1992 and rated 825 hp or greater | 5             | 3             | no standard   |
|                     |                      | After June 18, 1992 but prior to July 1, 2010 | 2.0 except under reduced speed, 80-100% of full torque conditions, may be 5.0 | 3             | no standard   |
|                     |                      | On or after July 1, 2010 | 1              | 3             | 1             |

After January 1, 2020, no 4-stroke lean burn engine authorized by this permit that existed at the site on January 1, 2012, shall emit NOx in excess of 2.0 g/bhp-hr. After January 1, 2015, no 4-stroke lean burn engines authorized by this permit that was installed at the site after January 1, 2012 shall emit NOx in excess of 2.0 g/bhp-hr. If an engine is installed at the site after January 1, 2015, it shall have three years from the date of authorization to be in compliance with a limit of 2.0 g/bhp-hr for NOx. This three year grace period follows the engine when it leaves the site if the engine also is authorized under this permit at the new site. The commission reserves the right to re-evaluate the upgrade requirement if EPA promulgates any standards for existing engines.

| Turbines            | Turbines greater than 500 hp shall not emit the most applicable of NSPS GG, NSPS KKKK, or NOx or CO in excess of 3.0 g/bhp-hr. |
### Table 10 Fugitive Component LDAR BACT Table

<table>
<thead>
<tr>
<th>FUGITIVE COMPONENT LEAK DETECTION AND REPAIR (LDAR) BEST AVAILABLE CONTROL TECHNOLOGY REQUIREMENTS TABLE</th>
<th>Additional Details</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Exceptions</strong> All fugitive components must meet the minimum design, monitoring, control and other emissions techniques listed in this Table unless the component's service meets one of the following exceptions:</td>
<td></td>
</tr>
<tr>
<td>Total uncontrolled potential to emit from all components ≤ 10 tpy</td>
<td>No expectation to estimate emissions. Note this exemption does not include lines with nitrogen that has been used as a sweep gas.</td>
</tr>
<tr>
<td>Nitrogen lines</td>
<td>No expectation to estimate emissions.</td>
</tr>
<tr>
<td>Steam lines (non contact)</td>
<td>No expectation to estimate emissions.</td>
</tr>
<tr>
<td>Flexible plastic tubing ≤ 0.5 inches in diameter, unless it is subject to monitoring by other state or federal regulations.</td>
<td>No expectation to estimate emissions, unless it is subject to monitoring by other state or federal regulations.</td>
</tr>
<tr>
<td>The operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure</td>
<td>No expectation to estimate emissions.</td>
</tr>
<tr>
<td>Mixtures in streams where the VOC has an aggregate partial pressure of less than 0.002 psia at 68°F.</td>
<td>No expectation to estimate emissions.</td>
</tr>
<tr>
<td>Components containing only noble gases, inerts such as CO₂ and water or air contaminants not typically listed on a MAERT such as methane, ethane, and Freon.</td>
<td>No expectation to estimate emissions.</td>
</tr>
<tr>
<td>Instrument monitoring is not required for pipeline quality sweet natural gas</td>
<td>Uncontrolled Emissions should be estimated. Must meet pipeline quality specifications</td>
</tr>
<tr>
<td>Instrument monitoring is not required when the aggregate partial pressure or vapor pressure is less than 0.044 psia at 68 °F or at maximum process operating temperature.</td>
<td>Uncontrolled Emissions should be estimated. This applies at all times, unless a control efficiency is being claimed for instrument monitoring, in which case there must be a record supporting that the instrument could detect a leak.</td>
</tr>
<tr>
<td>Instrument monitoring is not required for water waste lines containing less than 1% VOC by weight and operated at ≤ 1 psig</td>
<td>Uncontrolled Emissions should be estimated.</td>
</tr>
<tr>
<td>Instrument monitoring is not required for cooling water line components if cooling tower inlet water is monitored for VOC at the cooling tower.</td>
<td></td>
</tr>
<tr>
<td>Instrument monitoring is not required for CO₂ lines after VOC is removed. This is referred to as Dry Gas lines in 40 CFR Part 60 Subpart KKK, and defined as a stream having a VOC weight percentage less than 4 %; a weighted average Effects Screening Level (ESL) of the combined VOC stream is &gt; 3,500 μg/m³, and total uncontrolled emissions for all such sources is &lt; 1 ton per year at any OGS.</td>
<td>Uncontrolled Emissions should be estimated. The weighted average ESL, for process stream, X, with multiple VOC species will be determined by: ESLX = fa/ESL a + fb/ESLb + fc/ESLc + …. + fn/ESLn Where: n =total number of VOC species in process stream; ESLa = the effects screening level in μg/m³ for the contaminant being evaluated (published in the most recent edition of the TCEQ ESL list); fn=the weight fraction of the appropriate VOC species in relation to all other VOC in process stream.</td>
</tr>
<tr>
<td>At OGS sites where the total uncontrolled potential to emit from all components &lt; 25 tpy, instrument monitoring is not required on components where the aggregate partial pressure or vapor pressure is less than 0.5 psia at 100 °F or at maximum process operating temperature, unless the components are subject to monitoring by other state or federal regulations.</td>
<td>Uncontrolled Emissions should be estimated.</td>
</tr>
<tr>
<td>Minimum Design, Monitoring, Technique or Control for all fugitive components with uncontrolled potential to emit of ≥ 10 tpy VOC or ≥ 1 tpy H₂S</td>
<td></td>
</tr>
<tr>
<td><strong>Requirements</strong></td>
<td><strong>Additional Details</strong></td>
</tr>
<tr>
<td>Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes. Compliance with these requirements does not assure compliance with requirements of NSPS, NESHAPS or MACT, and does not constitute approval of alternate standards for these regulations.</td>
<td>To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation.</td>
</tr>
<tr>
<td>New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less</td>
<td></td>
</tr>
</tbody>
</table>
**FUGITIVE COMPONENT LEAK DETECTION AND REPAIR (LDAR) BEST AVAILABLE CONTROL TECHNOLOGY REQUIREMENTS TABLE**

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance.</td>
<td></td>
</tr>
<tr>
<td>Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line so that no leakage occurs. Except during sampling, both valves shall be closed.</td>
<td></td>
</tr>
<tr>
<td>Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.</td>
<td></td>
</tr>
<tr>
<td>Accessible valves shall be monitored by leak-checking for fugitive emissions quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored.</td>
<td></td>
</tr>
<tr>
<td>If an unsafe-to-monitor valve is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.</td>
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</tr>
<tr>
<td>For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.</td>
<td></td>
</tr>
<tr>
<td>All pump, compressor and agitator seals shall be monitored quarterly with an approved gas analyzer or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be instrument monitored. Seal systems that prevent emissions may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure or seals degassing to vent control systems kept in good working order. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.</td>
<td></td>
</tr>
</tbody>
</table>
| Minimum Design, Monitoring, Technique or Control for all fugitive components with uncontrolled potential to emit of ≥ 25 tpy or ≥ 5 tpy H2S | For a site where the total uncontrolled potential to emit from all components is < 25 tpy; Components found to be emitting VOC in excess of 10,000 parts per million by volume (ppmv) using EPA Method 21, found by visual inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H2S odors) or found leaking using the Alternative Work Practice in 40 CFR §60.18(g) - (i) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified. | Components subject to routine instrument monitoring with an approved gas analyzer under this leak definition my claim a 75% emission reduction credit when evaluating controlled fugitive emission estimates. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.
| For a site where the total uncontrolled potential to emit from all components is ≥ 25 tpy; Valves found to be emitting VOC in excess of 500 ppmv using EPA Method 21, found by audio, visual or olfactory inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H2S odors) or found leaking using the Alternative Work Practice in 40 CFR §60.18(g) - (i) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified and Pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv using EPA Method 21, found by audio, | Components subject to routine instrument monitoring under this leak definition my claim a 97% emission reduction credit when evaluating controlled fugitive emission estimates. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.

**Note:** Except during sampling, both valves shall be closed.
visual or olfactory inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or \( \text{H}_2\text{S} \) odors) or found leaking using the Alternative Work Practice in 40 CFR §60.18(g) - (i) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified.

Components not subject to a instrument monitoring program but found to be emitting VOC in excess of 10,000 ppmv using EPA Method 21, found by audio, visual or olfactory inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or \( \text{H}_2\text{S} \) odors) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified. All components are subject to monitoring when using the Alternative Work Practice in 40 CFR §60.18(g) - (i). Damaged or leaking valves, connectors, compressor seals, agitator seals, and pump seals found to be emitting VOC in excess of a required monitored leak definition in this table or found by audio, visual or olfactory inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced if repaired. A first attempt to repair the leak must be made within 5 days. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. 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.

Any site may reduce the controlled fugitive emission estimates by including components not required to be monitored in the quarterly instrument monitoring program or applying the lower leak definition of the more stringent program as appropriate.

Quarterly monitoring at a leak definition of 10,000 ppmv would equate to a 75% emission reduction credit when evaluating controlled fugitive emission estimates for the component. Quarterly monitoring at a leak definition of 500 ppmv for valves, flanges and connectors and 2000 ppmv for any other component would equate to a 97% emission reduction credit when evaluating controlled fugitive emission estimates for the component. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.

After completion of the required quarterly inspections for a period of at least two years, the operator of the OGS facility may change the monitoring schedule as follows:(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. If the owner or operator is using the Alternative Work Practice in 40 CFR §60.18(g) - (i), the alternative frequencies specified in this standard permit are not allowed.

At the discretion of the TCEQ Executive Director or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

Shutdown prior to Maintenance of Fugitive Components | Start-up after Maintenance of Components
--- | ---
All components shall be kept in good repair. During repair or replacement, emission releases from the emptying of associated piping, equipment, and vessels must meet the emission limits and control requirements listed under pipeline or compressor blowdowns. | When returning associated equipment and piping to service after repair or replacement of fugitive components, appropriate leak detection shall occur and correction, maintenance or repair shall be immediately performed if fugitive components are not in good working order.
# Table 11 Best Available Control Technology Requirements

<table>
<thead>
<tr>
<th>Source or Facility</th>
<th>Air Contaminant</th>
<th>Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Combined Control Requirements</td>
<td>&lt; 25 tpy VOC</td>
<td>No add on control is required if the continuous and periodic vents from all units, vessels and equipment (including normal operation process blow downs).</td>
</tr>
<tr>
<td></td>
<td>≥ 25 tpy VOC</td>
<td>All continuous and periodic vents on process vessels and equipment with potential emissions containing ≥ 1% VOC at any time must be captured and directed to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%.</td>
</tr>
<tr>
<td>Glycol Dehydration Unit</td>
<td>Uncontrolled PTE &lt; 10 tpy VOC</td>
<td>No control is required. Condensers included in the equipment constructed must be maintained and operated as specified by the manufacturer or design engineering.</td>
</tr>
<tr>
<td></td>
<td>VOC, BTEX, H₂S</td>
<td>All non-combustion VOC emissions shall be routed to a vapor recovery unit (VRU), the unit reboiler, or to an appropriate control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%. This includes the emissions from the condenser vent. Liquid waste or product material captured by a condenser must be enclosed and transferred to a unit compliant with the requirements of this table and the condenser must meet the requirements listed in the Control Device BACT Table with a minimum design control efficiency of 80%. For condensors, greater efficiencies may be claimed where enhanced monitoring and testing are applied following Table 7. If the unit reboiler is used to control the VOC emissions from the dehydrator (e.g. to control the condenser vent and the flash tank if one is present) the unit must be designed to efficiently combat those vented VOC's at least 70% of the time the unit is operated.</td>
</tr>
<tr>
<td></td>
<td>VOC, BTEX, H₂S</td>
<td>All non-combustion VOC emissions shall be captured and directed to an appropriate control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%.</td>
</tr>
<tr>
<td>Process Separators</td>
<td>Uncontrolled PTE ≥ 10 tpy VOC</td>
<td>Emission vents must be captured and directed to an appropriate control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%. If separator is pressurized, streams must be enclosed and the receiving unit or equipment must meet BACT as required by this table.</td>
</tr>
<tr>
<td></td>
<td>VOC, BTEX, H₂S</td>
<td>VOC with partial pressure &lt; 0.5 psia at maximum liquid temperature or 95 F which ever is greater. VOC, BTEX, H₂S</td>
</tr>
<tr>
<td>Oil/Water separators</td>
<td>VOC with partial pressure ≥ 0.5 psia at maximum liquid surface temperature or 95 F which ever is greater, VOC, BTEX, H₂S</td>
<td>The oil layer must have a floating cover over the entire liquid surface with a conservation vent to atmosphere or the vents must be captured and directed to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%.</td>
</tr>
<tr>
<td></td>
<td>VOC with partial pressure ≥ 0.5 psia at maximum liquid surface temperature or 95 F which ever is greater, VOC, BTEX, H₂S</td>
<td>If H₂S can exceed 24 ppmv in the vapor space the separator vent shall be captured and directed to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%.</td>
</tr>
<tr>
<td></td>
<td>Oil water separators where the material entering the separator may flash, VOC, BTEX, H₂S</td>
<td>May vent to atmosphere through vent no larger than 3 inch diameter.</td>
</tr>
<tr>
<td></td>
<td>H₂S</td>
<td>If the separator operates with more than 25,000 gallons (595 barrels) of liquid contained or is used as an oil storage tank, it shall be treated as a storage tank and meet those requirements.</td>
</tr>
<tr>
<td>Fuel Combustion Units including auxiliary fuel for combustion control devices</td>
<td>H₂S</td>
<td>Fuel for all combustion units at the site 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 (24 ppmv) of H₂S or 30 grains total sulfur compounds per 100 dscf, the operator shall maintain records, including at least quarterly measurements of fuel H₂S and total sulfur content, which demonstrate that the annual SO₂ emissions from the facility do not exceed the limitations listed in the SP registration.</td>
</tr>
<tr>
<td>Source or Facility</td>
<td>Air Contaminant</td>
<td>Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations</td>
</tr>
<tr>
<td>---------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Boilers, Reboilers, Heater-Treaters, and Process Heaters</td>
<td>NOx, CO, PM_{10/2.5}, VOC, HCHO, SO₂</td>
<td>If unit has a designed maximum firing rate of &lt; 40 MMBTU/hr, it must be designed and operated for good combustion and meet 0.036 lb/MMBTu (or 30 ppmvd @ 3% O₂) for NOₓ and 100 ppmvd @ 3% O₂ for CO.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>If unit has a designed maximum firing rate of ≥ 40 MMBTU/hr, it must be designed and operated for good combustion of CO, low-NOₓ burners and meet 0.01 lb/MMBTu (or 9 ppmvd at 3% O₂) for NOₓ and 50 ppmvd @ 3% O₂ for CO.</td>
</tr>
<tr>
<td>GasFired Turbines</td>
<td>NOx, CO, PM_{10/2.5}, VOC, HCHO, SO₂</td>
<td>Units shall be designed and operate with low NOₓ combustors and meet 25 ppmvd @ 15% O₂ for NOₓ and 50 ppmvd @ 15% O₂ for CO.</td>
</tr>
<tr>
<td>All Tanks</td>
<td>Uncontrolled PTE of &lt; 1.0 tpy VOC or &lt; 0.1 tpy H₂S</td>
<td>Open-topped tanks or ponds containing VOCs or H₂S are allowed.</td>
</tr>
<tr>
<td>All Tanks</td>
<td>Uncontrolled PTE of ≥ 1.0 tpy VOC or ≥ 0.1 tpy H₂S</td>
<td>Open-topped tanks or ponds containing VOCs or H₂S are not allowed.</td>
</tr>
<tr>
<td>Crude oil, Condensate, Treatment chemicals, Produced water, Fuel, Slop/Sump Oil and any other storage tanks that contain a VOC or a film of VOC on the surface of water.</td>
<td>VOC with partial pressure &lt; 0.5 psia at maximum liquid surface temperature or 95 F which ever is greater, or with uncontrolled PTE of &lt; 5 tpy VOC from working and breathing losses VOC, BTEX, H₂S</td>
<td>All tanks with a storage capacity greater than 500 gallons must be submerged fill.</td>
</tr>
<tr>
<td></td>
<td>VOC with partial pressure ≥ 0.5 psia at maximum liquid surface temperature or 95 F (which ever is greater), or with uncontrolled PTE of ≥ 5 tpy from working and breathing losses VOC, BTEX, H₂S</td>
<td>All tanks with a storage capacity greater than 500 gallons must be submerged fill. Un-insulated tank exterior surfaces exposed to the sun shall be of a color that minimizes the effects of solar heating (including, but not limited to, white or aluminum). To meet this requirement the solar absorptance should be 0.43 or less, as referenced in Table 7.1-6 in AP-42. Paint shall be maintained in good condition. If a new or modified tank cannot be painted white or other reflective color, then a VRU may be used to control emissions. Exceptions to the color requirement include the following: (A) Up to 10% of the external surface area of the roof or walls of the tank or vessel may be painted with other colors to allow for identifying information or aesthetic purposes; and (B) If a local, state or federal law or ordinance or private contract which predates this standard permit’s effective date establishes in writing tank and vessel colors other than white. If applicable, a copy of this documentation must be provided to the commission upon registration.</td>
</tr>
<tr>
<td></td>
<td>VOC with uncontrolled PTE of ≥ 5 tpy</td>
<td>Tank vents shall be captured and directed to an appropriate control device listed in the Control Device BACT Table such as a vapor recovery unit (VRU) with a minimum design control efficiency of at least 95%. Existing tanks and vessels (including temporary liquid storage tanks) which are not increasing emissions at an OGS using shall also meet this requirement no later than 180 days after a registration renewal as of January 1, 2016.</td>
</tr>
<tr>
<td>Source or Facility</td>
<td>Air Contaminant</td>
<td>Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations</td>
</tr>
<tr>
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</tr>
<tr>
<td>Truck Loading</td>
<td>VOC with partial pressure $&lt;\ 0.5$ psia at maximum liquid surface temperature or $95\ F$ which ever is greater, or with uncontrolled PTE of $&lt;\ 5$ tpy VOC VOC, BTEX, H$_2$S</td>
<td>Loading is recommended to be performed with submerged filling, or vapor balancing back to the tank and any subsequent recovery or control device.</td>
</tr>
<tr>
<td></td>
<td>VOC with partial pressure $\geq\ 0.5$ psia at maximum liquid surface temperature or $95\ F$ which ever is greater VOC, BTEX, H$_2$S</td>
<td>Splash loading and uncontrolled vacuum truck loading is not allowed. Loading shall be performed with a control effectiveness of at least 42% as compared to splash loading. Loading may occur by submerged filling or equivalent prevention or recovery technique as listed in Table 12.</td>
</tr>
<tr>
<td></td>
<td>VOC with uncontrolled PTE of $\geq\ 5$ tpy VOC VOC, BTEX, H$_2$S</td>
<td>Loading vapors shall be captured and directed to an appropriate control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 98%, routed to a vapor recovery unit (VRU) with a control effectiveness of at least 95%, or vapor balanced back to the delivering storage tank equipped with a VRU, or connected to a control device listed in the Control Device BACT Table with a minimum design control efficiency of at least 95%.</td>
</tr>
<tr>
<td>Controlled Loading</td>
<td>Where loading control is required, the collection or capture system must be connected to the tank truck so all displaced vapors are directed to the control device and the control device is operational before loading is commenced. When properly connected the capture efficiency will be assumed to be 70% efficient at capturing the displaced truck vapors. The capture efficiency may be assumed to be 98.7 percent efficient when the tanker truck has certification that the tank has passed vapor-tightness testing within the last 12 months using the methods described in 40 CFR 60, Subpart XX. The capture efficiency may be assumed to be 99.2 percent efficient when the tanker truck has certification that the tank has passed vapor-tightness testing within the last 12 months using the methods described in 40 CFR 63, Subpart R. Loading shall be discontinued when liquid or gas leaks from the loading or collection system are observed.</td>
<td></td>
</tr>
<tr>
<td>Cooling Tower Heat Exchange System</td>
<td>VOC, BTEX, PM$_{10/2.5}$</td>
<td>Heat exchange systems must be non-contact design (i.e. designed and operated to avoid direct contact with gaseous or liquid process streams containing VOC, H$_2$S, halogens or halogen compounds, cyanide compounds, inorganic acids, or acid gases). Systems with heat exchangers that cool a fluid with VOC shall meet the following: The cooling water must be at a higher pressure than the process fluid in the heat exchangers or the cooling tower water must be monitored monthly for VOC emissions using TCEQ Sampling Procedures Manual, Appendix P dated January 2003 or a later edition. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. Cooling water VOC concentrations greater than 0.08 ppmv indicate faulty equipment. CT shall be designed with drift eliminators. If the repair of a heat exchanger would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next planned shutdown or 180 days if no shutdowns are scheduled.</td>
</tr>
<tr>
<td>Control Devices and Facilities</td>
<td>Air Contaminant of Concern</td>
<td>Minimum Acceptable Design, Control or Technique, Control Efficiencies, and Other Details during Production Operations</td>
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<tr>
<td><strong>Vapor Recovery Systems</strong></td>
<td>VOC</td>
<td>VRUs that are used at oil and gas sites to control emissions must be designed for at least 95% control for units where appropriate design requirements and conditions are practiced and appropriate monitoring, as listed in Table 8. VRUs may claim up to 99% control for units where enhanced monitoring is applied. All valves must be designed and maintained to prevent leaks. All hatches and openings must be properly gasketed and sealed with the unit properly connected. Downtime is limited to a rolling 12 month average of 5% or 432 hr/per rolling 12 months and waste vents shall be redirected to an appropriate control device if possible during down time.</td>
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<tr>
<td></td>
<td>H2S</td>
<td></td>
</tr>
<tr>
<td><strong>Flares</strong></td>
<td>VOC</td>
<td>Flares used for control of emissions from normal operation, planned MSS, or emergency/upsets are required to meet at least 98% VOC and H2S destruction efficiency of the streams directed to the control. (Note, for the calculation the thermal conversion destruction of H2S and other sulfur compounds is assumed to be 100% to SO2 plus 2% of the H2S is assumed to be emitted as H2S.) To meet the required destruction efficiency flares must be designed and operated in accordance with 40 Code of Federal Regulations (CFR), §60.18, General Control Device Requirements, including specifications of minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring. If necessary to ensure adequate combustion, sufficient auxiliary fuel shall be added to make the gases combustible per the §60.18 standard. 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 when all streams routed to the flare are specifically directed there through control valves by an operator and if no streams are directed to the flare for control through pressure relief valves or automated emergency control valves. The flare must be lit at all times that there is an emissions stream being vented to the flare. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed at total of 5 minutes during any 2 consecutive hours. Acid gas flares which must comply with opacity limits and records in accordance with 30 TAC 111.111(4), regarding Gas Flares, are exempt from this visible emission limitation. Flares may be designed with steam or air assist to help reduce visible emissions from the flare but must meet the appropriate requirements in 40 CFR 60.18. At no time shall the flare tip velocity exceed the allowable tip velocity in 60.18. At no time shall minimum heating values fall below the associated minimum heating value in 60.18.</td>
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<tr>
<td></td>
<td>BTEX</td>
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<td></td>
<td>NOx</td>
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<td></td>
<td>CO</td>
<td></td>
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<tr>
<td></td>
<td>SO2</td>
<td></td>
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<td></td>
<td>H2S</td>
<td></td>
</tr>
<tr>
<td><strong>Oxidation or Combustion</strong></td>
<td>VOC</td>
<td>These units may claim design destruction efficiency from 98% to 99.9% depending on the design and the level of monitoring and testing applied. Devices with intermediate monitoring, designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1400 degrees Fahrenheit (°F) for 0.5 seconds, residence time; or designed to meet the parameters of a flare with minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring as found in 40 CFR § 60.18, but within a full or partial enclosure may claim a design destruction efficiency of at least 98%. Devices with enhanced monitoring and ports and platforms to allow stack testing may claim a 99 % efficiency where the devices are designed for the variability of the waste gas streams they control, with a fire box or fire tube designed to maintain a temperature above 1400 degrees Fahrenheit (°F) for 0.5 seconds, residence time. The devices that can claim 99% destruction efficiency as noted above may claim 99.9% destruction efficiency if stack testing is conducted and confirms the efficiency and the enhanced monitoring is adjusted to ensure the continued efficiency. Temperature and residence time requirements may be modified if stack testing is conducted to confirm efficiencies.</td>
</tr>
<tr>
<td><strong>Control Devices, Thermal Oxidizers and Vapor Combustors</strong></td>
<td>BTEX</td>
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</tr>
<tr>
<td></td>
<td>NOx</td>
<td></td>
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<tr>
<td></td>
<td>SO2</td>
<td></td>
</tr>
<tr>
<td></td>
<td>H2S</td>
<td></td>
</tr>
<tr>
<td><strong>Condensers directly</strong></td>
<td>VOC</td>
<td>Condensers shall achieve a minimum of 80% recovery effectiveness for VOCs. Outlet gas temperature must be continuously measured and shall not exceed the temperature determined by the manufacture or design engineer’s specification set to assure compliance with the control efficiency below the dew point of the VOCs controlled. Effectiveness may require sampling or monitoring upon request by the TCEQ or local programs and is required in all cases where greater than 80% control is claimed.</td>
</tr>
<tr>
<td><strong>associated with amine units</strong></td>
<td>BTEX</td>
<td>When used for control of waste gas streams, may claim 90% to 99% destruction efficiency depending on the design and level of monitoring applied. The 90% destruction may be claimed where the waste gas is delivered to the flame zone or combustion fire box with basic monitoring as specified Table 8. Any value greater than 90% and up to 99% destruction efficiency may be claimed where enhanced monitoring and/or testing are applied as specified Tables 7 and 8. If the waste gas is premixed with the primary fuel gas and used as the primary fuel in the device through the primary fuel burners, 99% destruction may be claimed with basic monitoring as specified Table 8. In systems where the combustion device is designed cycle on and off to maintain the designed heating parameters, and may not fully utilize the waste gas stream, enhanced monitoring is required to claim any control.</td>
</tr>
<tr>
<td><strong>and glycol dehydrators</strong></td>
<td>H2S</td>
<td></td>
</tr>
<tr>
<td><strong>Process reboilers, heaters,</strong></td>
<td>VOC</td>
<td></td>
</tr>
<tr>
<td><strong>and furnaces directly</strong></td>
<td>BTEX</td>
<td></td>
</tr>
<tr>
<td><strong>associated with process units</strong></td>
<td>H2S</td>
<td></td>
</tr>
<tr>
<td><strong>not add-on controls</strong></td>
<td></td>
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</tbody>
</table>