The Texas Commission on Environmental Quality (TCEQ or commission) proposes the repeal of §106.352, Oil and Gas Production Facilities, and proposes new §106.352, Oil and Gas Site.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE PROPOSED RULES

The commission is in the process of evaluating all permits by rule (PBR) 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, start-up, and shutdown (MSS) activities; and allow the commission to more effectively focus resources on facilities that significantly contribute air contaminants to the atmosphere. Through this study, the commission has determined a need to significantly revise the PBR and standard permit for oil and gas facilities or groups of facilities at a site (OGS). In addition, recent monitoring data indicates updated regulatory oversight would be beneficial to ensure protectiveness for air contaminants such as benzene, hydrogen sulfide ($H_2S$), 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 authorizations for OGS are improved for enforceability, updated based on current scientific information, and to properly regulate all operations.

In a concurrent action, the commission is developing a new non-rule standard permit for the construction and modification of oil and gas facilities which will replace 30 TAC §116.620, Installation and/or Modification of Oil and Gas Facilities. The new PBR and standard permit is proposed to provide an updated, comprehensive, and protective authorization for many common OGS in Texas. The proposed new PBR and standard permit will include operating specifications and emissions limitations for typical equipment (facilities) during normal operation, which includes production and planned MSS. The proposed PBR and standard permit will specifically address the appropriateness of multiple authorizations at one contiguous property and would reference the many new federal standards which have been promulgated by the United States Environmental Protection Agency (EPA), as well as include revised criteria for registration and changes at existing, authorized sites.

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 executive director has established a hierarchy of authorization mechanisms. The most negligible sources are covered under §116.119, De Minimis 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 under 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 issued under Chapter 116, Subchapter F, Standard Permits, 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 rule exactly, with no exceptions. The next category of available authorizations is case-by-case state new source review (NSR) permits issued under §116.111, General Application. 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.

Currently, an OGS may be authorized by PBR, standard permit, case-by-case NSR permit, or a combination of these authorizations. This proposed PBR is being developed to provide an updated, comprehensive, and protective authorization for many common OGS in Texas. The proposed PBR will include specifications and limitations for typical equipment (facilities) during normal operation, including production as well as planned MSS. The proposed PBR has 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 PBR and standard permit address the appropriateness of multiple authorizations at one contiguous property. This proposal also includes revised criteria for registration and scope of protectiveness reviews for changes at existing, authorized sites.

Many stakeholders commented that a periodic renewal of PBR registrations for OGS should occur. At this time, the commission is not proposing a required registration renewal cycle. PBRs are issued for certain types of facilities or changes within facilities which the commission has determined will not make a significant contribution of air contaminants to the atmosphere pursuant to the THSC, §382.057 and §382.05196. It is not necessary for the commission to require a registrant to renew their PBRs if the commission has already determined that these emissions will not significantly contribute to air pollution. If the commission determines that the PBR no longer ensures that the facilities it authorizes will only make insignificant contributions to air pollution, then the commission will update the PBR to ensure compliance with THSC, §382.057 and §382.05196.

One of the continuing limitations for the proposed PBR would limit the authorizations to OGS which do not require federal preconstruction authorization under the prevention of significant deterioration (PSD) requirements of 40 Code of Federal Regulations (CFR) Part 51 or the nonattainment new source review (NNSR) requirements of 40 CFR Part 52. 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 claims will not adversely impact human health and welfare.

For each type or group of typical OGS facilities and activities, the executive director 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 what 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 what are the impacts of the emissions protective of public health and welfare?

In 2006, the commission distributed a preliminary proposal for OGS, which included updates based on then current 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 proposal package. 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 PBR may only consist of the facilities and operations evaluated by the commission. The executive director 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 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, or 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, or absorption and 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, or thermal destruction devices); and other facilities meeting the conditions of certain PBRs, including: §§106.181, Used-Oil Combustion Units; 106.183, Boilers, Heaters and Other Combustion Devices; 106.261; Facilities (Emission Limitations); 106.262, Facilities (Emission and Distance Limitations); 106.264, Replacements of Facilities; 106.351, Salt Water Disposal (Petroleum); 106.352; 106.353, Temporary Oil and Gas Facilities; 106.471, Storage or 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.

The commission developed an updated, draft, informal proposal and on April 8, 2010, held a stakeholders meeting. This meeting included a webcast presentation, questions, and feedback from industry and the general public. All parties were asked to submit written comments for consideration of issues and changes by April 30, 2010. Over 140 sets of comments were received and included over 1,800 individual comments, proposals, information, or opinions which were further considered by the commission. A summary of the most common comments and how they may have been considered for this proposal is available through the commission webpage for this rule project.

Additional information was requested from stakeholders or explored by the executive director to help develop this proposal. Where sufficient information was available, emissions, potential impacts, BMP, MSS, and control technologies 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, demethanizers, 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, not including/including catalysts with ammonia/urea injection.

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/degassing, 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(R), regenerative or non regenerative sweetening systems with solid or liquid treatment chemicals, cooling towers, cryogenic units, demethanizers, 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 were 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.

The details of this evaluation (sources, operations, controls, emissions, applicable state and federal regulations, and potential impacts) are included in the proposed standard permit for OGS available through the commission's webpage.

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 Site Assistance Visit Plus (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: establishment of spill prevention, control, and countermeasure 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 of secondary containment areas; instructing operators to not bypass interlocks, alarms, or specifically alter set points without authorization; isolating 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 volatile organic compound (VOC) control; use of conservation vents on fixed-roof tanks; use of vapor recovery (vapor balance) systems; store 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, etc.; 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; and 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 innovative 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; lower EPA inspection priority; reduced reporting under Maximum Achievable Control Technology (MACT); extended hazardous waste storage time from 90 to 180 days; and reduced self-inspections for certain Resource Conservation and Recovery Act facilities. The executive director 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 30 TAC Chapter 114, Control of Air Pollution from Motor Vehicles, 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. If an engine can be retrofitted or replaced to reduce nitrogen oxides ($NO_X$) 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.

SECTION BY SECTION DISCUSSION

The executive director has completed a comprehensive evaluation of emissions and impacts from OGS (see details in the proposed Air Quality Standard Permit for Oil and Gas Sites technical summary) and is proposing the new PBR and a concurrent standard permit for OGS to ensure these authorization mechanisms effectively regulate emissions. The proposed PBR applies to the specifically reviewed facilities and the operation of groups of facilities which produce, condition, process, handle, and transfer petroleum liquids and gases whose overall effects on air quality are insignificant. The overall limits of all PBRs include site-wide emissions less than 250 tons per year (tpy) of $NO_X$ and carbon monoxide (CO), and 25 tpy of any other air contaminant, as well as criteria to ensure protection of public health and welfare, BMPs, incentives for recovery, and practically enforceable recordkeeping. The proposed section authorizes two distinct levels of OGS production facilities and associated MSS operations. The first level is for the smallest of emissions sites, and the second level for insignificant, but more complex operations.

The commission proposes the repeal of the existing section and proposes a new PBR for OGS. The repeal will prevent conflicting authorization methods for the same types of facilities. The following discussion describes proposed new §106.352.

Proposed subsection (a) outlines the applicability and scope of registrations under this new PBR. 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 PBR.

The majority of the proposed PBR requirements are only applicable to new facilities or increases at existing PBR 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 PBR 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 PBR 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 other PBRs to authorize other facilities not covered under this section provided the protectiveness conditions of subsection (b)(6) of this section are met to ensure comprehensive protectiveness of this authorization and prevent partial permitting or circumvention of these proposed PBR requirements.

Subsection (a)(1) also prohibits the use of this PBR to authorize operationally related facilities at a site where facilities are authorized under §116.111, except for the purpose of authorizing MSS or under the OGS standard permit. To ensure that site-wide authorizations are used at an OGS, facilities requiring authorization by a case-by-case permit cannot use this PBR for new facilities or make changes to existing facilities. New facilities or changes to existing permitted facilities may use any other applicable and specific PBR. The PBRs which likely could be claimed, registered, or certified (as appropriate) include the following: §§106.181, 106.183, 106.261, 106.262, 106.264, 106.351, 106.353, 106.471, 106.472, 106.473, 106.475, 106.476, 106.478, 106.492, 106.511, and 106.512.

Case-by-case permitted OGS under §116.111 may use this proposed new section for the authorization of planned MSS activities. The requirements included in the proposed PBR are based on BMP, and appropriate impacts limitations based on a specific evaluation of reviewed or expected planned MSS activities at OGS. If a permitted site's planned MSS can meet the proposed PBR limits, there would be no gain for the agency or public to require a permit review as of January 5, 2012. As with all PBR claims, registrations, or certifications at a permitted site using PBRs, the PBRs must be incorporated into the underlying site's permit at the next amendment or renewal, so at some reasonable point in the future (no longer than 10 years), the OGS permit will have a comprehensive listing of all requirements and limitations. If a permitted site cannot meet the PBR limitations, then a permit or permit amendment would be required by January 5, 2012, to authorize any planned MSS.

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 PBR, the site cannot be authorized.

Subsection (a)(3) prohibits the use of this section to authorize upsets, emergencies, or malfunctions. The executive director believes these types of activities and releases are not appropriate to be authorized in any circumstance, and instead should be covered under 30 TAC §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 PBR is to ensure that new OGS or changes to existing sites appropriately focus on protection of public health and welfare, BMPs, 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 PBR, including federal permit applicability, PBR 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, consider 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 THSC, §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 PBR 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 PBR to include building which was in use as a single or multi-family residence, school, or place of worship at the time this section is claimed. The reason for the phrase "at the time this section is claimed" 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 section.

The term residence has been defined for this PBR 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 II New College Dictionary, 1995, 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." 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 PBR 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 PBR states that all measurements of distance to receptors shall be taken from the project location which required registration under the proposed PBR 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 PBR 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 2912, 77th Legislative Session, 2001. The law was codified in the statute under THSC, §382.065, 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 section. 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 OGS 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 PBR 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 §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 section 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 PBR registration, but are not required to meet all requirements of the proposed PBR. 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 PBR (and standard permit) are proposed to have a stipulated distance of no more than 1/4 mile and that the facilities under a single PBR 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 section. Subsection (b)(5)(D) limits all OGS registrations under this section to a maximum collective limit of air emissions. The rule establishes a site-wide emission limit for all OGS facilities under a single registration to 250 tpy $NO_X$ or CO, or 25 tpy of any other air contaminant category.

Subsection (b)(5)(E) addresses planned MSS of OGS facilities. In §101.222, Demonstrations, 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 PBR 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 PBR 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. This proposal also allows OGS with regular permits to authorize planned MSS as covered by this section to authorize associated activities and emissions using this PBR, thus avoiding unnecessary permit amendment reviews for insignificant emissions.

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 PBR requires all facilities, regardless of authorization type, located within approximately 1/4 mile (1,400 feet) of a project requiring registration under this section be evaluated, including fugitive components. To ensure only appropriate review, if a claim under this section 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 PBR to ensure that property lines or receptors in close proximity to the OGS are evaluated.

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 $NO_X$ (hourly National Ambient Air Quality Standards (NAAQS) 188 micrograms per cubic meter ($\mu g/m^3$), annual NAAQS 100 $\mu g/m^3$), CO (hourly NAAQS 40,000 $\mu g/m^3$), sulfur dioxide ($SO_2$) (new hourly NAAQS 196 $\mu g/m^3$, most stringent state 30-minute standard 715 $\mu g/m^3$), particulate matter (PM) less than or equal to ten microns in diameter ($PM_{10}$) (24-hour NAAQS 150 μg/$m^3$, annual NAAQS 50 μg/$m^3$), PM less than or equal to 2.5 microns in diameter ($PM_{2.5}$) (24-hour NAAQS 35 μg/$m^3$, annual NAAQS 15 μg/$m^3$). $H_2S$ does not have a NAAQS, but is regulated by §112, Control of Air Pollution from Sulfur Compounds (most stringent state standard 108 μg/$m^3$, statewide standard 162 μg/$m^3$). Also present at OGS, but are not limited to, are natural gas, condensate, crude oil, benzene, toluene, ethylbenzene, xylene, and other common constituents. These constituents must meet their respective effects screening levels (ESLs) 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 air quality 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 2 - 6 in subsection (1) 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 1 lb/hr. 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 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 feet per second (ft/sec), and temperatures from 80 degrees Fahrenheit (F) to 800 degrees 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 actual cubic feet per minute (acfm) at 120 degrees 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 subsection (1), Table 2.

Fugitive sources comprise all fugitive emissions from a representative OGS. Fugitives were represented as three sources. Fugitive emissions were represented as three sources: a circular area source with a 3-foot release height and 30-foot 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 fugitive 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 horsepower (hp), 100% load at a stack flow rate of 4,800 acfm at 900 degrees 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 degrees 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 $NO_x$ to nitrogen dioxide ($NO_2$).

Heaters, boilers, and similar process units should use subsection (1), 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 subsection (1), Tables 3 and 4. Turbines were not separately analyzed because of limited registrations involving turbines. Since engines have worse dispersion characteristics than turbines, subsection (1), 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 $NO_X$, CO, $SO_2$, and $PM_{10}$ 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 $H_2S$) converts to $SO_2$, 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 in accordance with New Source Performance Standards (NSPS) in 40 CFR §60.18, General Control Device and Work Practice Requirements, 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 degrees F), exit velocity of 20 meters per second (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 100 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 Numbers 9880 and 10434. The modeling files can be found in the NSRG library under Document Numbers 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.

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 as previously discussed; 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.

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.

Lastly, the commission proposes to restrict emission changes at existing OGS facilities to ensure continuing protectiveness of previously authorized facilities. The following summarizes the results of the commission's review:

CO has a 1-hour ambient air standard of 40,000 $\mu g/m^3$ and an 8-hour standard of 10,000 $\mu g/m^3$, 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 100 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; therefore, a registration-specific impacts analysis is not necessary or required by this proposal. However, registrations under the proposed PBR would be limited to a maximum 250 tpy, or 57 lb/hr (assuming steady-state emission releases).

PM less than $PM_{10}$ and particulate matter less than or equal to $PM_{2.5}$ have 24-hour ambient air standards of 150 $\mu g/m^3$ and 35 $\mu g/m^3$, respectively. Additionally, the annual ambient air standard for $PM_{2.5}$ is 15 $\mu g/m^3$. 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 100 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; therefore, a registration-specific impacts analysis is not necessary or required by this proposal.

$SO_2$ 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 $\mu g/m^3$. The EPA has finalized a new hourly NAAQS of 196 $\mu g/m^3$ (based on the EPA announcement June 3, 2010). The most quantifiable sources of $SO_2$ 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 feet), lowest dispersing stack height (20 feet), and the new proposed NAAQS (196 $\mu g/m^3$), 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 100 reviewed OGS PBR registrations in 2010, the range of $SO_2$ 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 $SO_2$ 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 $SO_2$ occurs from flares, there are other releases of $SO_2$ 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 $SO_2$, 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. Based on this information, 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.

$H_2S$ has several state ambient air standards, depending on location. The most stringent is a 30-minute standard of 108 $\mu g/m^3$. There are many quantifiable sources of $H_2S$ 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 feet) and lowest dispersing stack height (3 feet), 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 100 of reviewed OGS PBR registrations in 2010, the range of $H_2S$ 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. 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 Chapter 112, may have more stringent requirements due to the differences in the definition of receptor.

The $NO_X$ standard is used to evaluate the $NO_2$ ambient 1-hour air standard of 188 $\mu g/m^3$ and an annual ambient air standard of 100 $\mu g/m^3$ as measured at the nearest property line to the authorized facilities. The most substantial sources of $NO_X$ at OGS are engines. Using a conservative impacts evaluation for engines, the ambient ratio factor of 75% of $NO_X$ is $NO_2$, at the shortest distance (50 feet) and lowest dispersing stack height (8 feet), 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 100 reviewed OGS PBR registrations in 2010, the range of $NO_X$ 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 $NO_2$ NAAQS. Therefore, applicants should be required to demonstrate impacts of $NO_X$ for distances between 50 feet and 2,700 feet for all combustion sources greater than 9 lb/hr.

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 $\mu g/m^3$), crude oil (hourly 3,500 $\mu g/m^3$), condensate (hourly 3,500 $\mu g/m^3$), benzene (hourly 170 $\mu g/m^3$ and annual 4.5 $\mu g/m^3$), toluene (640 $\mu g/m^3$), xylene (350 $\mu g/m^3$), other typical chemicals found in petroleum streams, and formaldehyde (hourly 15 $\mu g/m^3$) 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 stream thermal control devices, and blowdowns during planned MSS activities.

44 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,

methylcyclohexane, 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 (equals a 10% statistically cut-off) from the 44 registrations. The chemicals which showed the highest potential culpability for impacts were: benzene, toluene, xylene, ethylbenzene, cyclohexane, and methylcyclohexane.

Ethylbenzene, cyclohexane, and methylcyclohexane 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 methylcyclohexane 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 cyclohaxane 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 methylcylcohexane had represented emissions which were below the 0.80 lb/hr allowable emissions for methylcyclohexane 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. Based on this evaluation, emissions less than 0.08 lb/hr of xylene do not need an impacts evaluation. However, evaluation for xylene should occur for emissions greater than 0.08 lb/hr for distances to receptors between 50 feet and 2,700 feet.

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 lb/hr established in the rule. Additionally, total hourly and annual allowable emissions of VOCs and benzene and allowable lb/hr 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 $\mu g/m^3$ and an annual ambient air standard of 3.3 $\mu g/m^3$. The most quantifiable source of formaldehyde emissions at OGS is from engines. Using the conservative impacts evaluation tables at the shortest distance (50 feet) and lowest dispersing stack height (8 feet), 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 100 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. 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.

Proposed subsection (b)(7) addresses two requirements which apply to existing OGS even if no changes are occurring. The first requirement in subsection (b)(7)(A) addresses requirements for planned MSS at an existing OGS using a previous version of the OGS standard permit. In §101.222, 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 PBR 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 PBR clearly reviewed these emissions. It should also be noted that MSS is not required to be authorized and existing sites will not lose their current affirmative defense opportunities until 2012. All existing OGS which have claimed historical versions of the OGS standard permit should use the proposed limits for any MSS releases after the PBR has been issued by the commission. Therefore, any limits or controls are only triggered when an OGS authorizes these activities. 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.

The planned MSS associated with existing OGS does not 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.

Proposed subsection (b)(7)(B) requires submittal of a basic identifying information notification via the E-permits system no later than January 1, 2013. The commission also proposes subsection (b)(7)(B) to address the concern relating to where all the OGS are located and what authorization mechanism they are claiming for existing OGS using a previous version of the OGS standard exemption or PBR which has determined at least basic identifying no physical or operational changes. To ensure an accurate accounting for all oil and gas entities authorized in Texas, the commission proposes to require a minimum of basic identifying information on any active site. The submittal of core data and an overview of authorization type or registration number are proposed to be all of the information needed to address issues with OGS areas throughout the state. Currently, and in the past, the commission has not had a complete inventory or list of all OGS. The commission will establish a form and process through the E-permitting system of the agency so no actual paper forms or mailings will be generated by this requirement. The proposed deadline is January 1, 2013, or approximately 2 years from adoption. This is a reasonable period to submit this information on OGS operations throughout the state for reference to the agency considering there are many companies which have hundreds of OGS in Texas.

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. Subsection (c)(1) covers existing OGS which are authorized under previous versions of the OGS PBR and the changes which may occur at those locations. Subsection (c)(2) covers registration requirements for all new registrations or updates to existing registrations. Subsection (c)(3) covers the situations where the executive director may deny a registration.

Subsection (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 subsection (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 subsection (b)(5). In both of these circumstances, the new and changing facilities must be evaluated under all portions of the proposed PBR. 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 PBR. 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 $NO_X$, 0.01 tpy benzene, and 0.05 tpy $H_2S$. These values were established well below any applicable threshold and should not contribute to any impact evaluation exceedances. The values proposed for VOC and $NO_X$ are no greater than 4% of the total maximum annual emissions which would be allowed under this section (Level 2 of the proposed PBR). The values proposed for $H_2S$ and benzene are approximately 2% of the total annual emissions proposed (Level 1 of the proposed PBR). Additional details on these values are discussed in paragraphs regarding subsections (g) and (h). 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 BMPs, 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 $NO_X$, 0.05 tpy benzene, or 0.1 tpy $H_2S$. The values proposed for VOC and $NO_X$ 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). The values proposed for $H_2S$ and benzene are less than 5% of the total annual emissions proposed for Level 1 of this PBR. After any one of the limits is met, a registration (or registration update) under this section would be required so that all appropriate PBR 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 PBR.

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 PBR 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 as explained in proposed subsection (c)(2)(A).

Proposed subsection (c)(2) establishes expectations for all registrations under this section and reminds all permit holders that this section does not authorize any major sources or major modifications. In addition, any facility or activity which also is subject to a federal NSPS, National Emissions Standards for Hazardous Air Pollutants (NESHAP), or MACT must meet those requirements, regardless of the requirements of this section. Finally, all facilities and activities must also comply with any applicable state regulation.

Proposed subsection (c)(3) clarifies that 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 section. 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 section for good cause. In this subsection, the reasons that constitute "good cause" include: failing to meet the requirements of the PBR; 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 section. 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 OGS traditionally using this PBR so a comprehensive review can be assured. The commission has evaluated numerous facilities, along with supporting infrastructure equipment for this PBR, 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(R), 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 PBR. Several units and operations were excluded for various reasons for consideration under the PBR. Subsection (d)(2)(A) discusses sulfur recovery units (SRU) 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, Nonattainment and Prevention of Significant Deterioration Review Definitions, which cannot be authorized by a PBR. 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 SRUs, it was concluded by the executive director 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 $H_2S$ 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 was not able to obtain sufficient processing and emission data for production, or MSS emissions on these units from applications it reviewed. As a result the executive director 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 section. These are subsurface facilities involved in waste disposal activities, which are beyond the scope of the OGS production processes at the sites evaluated. Instead, many of these facilities and operations can claim PBR, §106.351. Transfer of liquefied petroleum gases, 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's review because larger OGS 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. Proposed subsection (d)(2)(H) also prohibits use of the PBR 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, PBR authorizations will not contribute to existing, monitored problems in specified areas of the state.

The commission proposes subsection (e) to require BMPs and minimum requirements for new and changed facilities at an OGS authorized under this proposed section. 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 subsection (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 for 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.

Proposed subsection (e)(4) addresses engines and turbines. 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 $NO_X$, VOC and CO requirements. These criteria are based on Tier I BACT determinations, current Chapter 117, Control of Air Pollution from Nitrogen Compounds, requirements and federal NSPS.

For turbines, no change is recommended from the emission limitation currently in §106.512. For engines, this proposed requirement is based on the engine type and manufacture date. An engine type is either rich burn or lean burn. The existing definition of rich burn from §106.512 is "a gas-fired spark-ignited engine that is operated with an exhaust oxygen content less than 4.0% by volume." A lean-burn engine is all other gas-fired spark-ignited engines. The manufacture date is the date of original manufacture unless reconstructed as defined by NSPS regulations in which case that date becomes the manufacture date. These requirements are equivalent to or slightly less stringent than BACT for all new and modified engines. Since many older engines may not be able to be modified to reduce $NO_X$ emissions to the specified levels without significant reconstruction, the commission is proposing certain specific criteria which allows these older engines to be replaced or retrofitted with controls over a reasonable period of time (no later than January 1, 2020, for rich burn engines and no later than January 1, 2030 for lean burn engines). $NO_X$ emission limits prior to those dates are based on the existing requirements of §106.512 and the newly promulgated NSPS standards for spark-ignited stationary engines. Any rich burn engine less than 100 hp does not have an applicable standard under the PBR because these engines typically are not controlled. Two-stroke lean-burn engines less than 500 hp do not have an emission standard because they typically are used in specialized service and are insignificant as a class. Subsection (1), Table 9 applies standards to rich-burn engines greater than 100 hp and lean-burn engines greater than 500 hp. Emission limitations are also established for CO and VOC emissions from engines and CO emissions from turbines, representing reasonable control while allowing for retrofits for $NO_X$ control. Fuel for engines is limited to sweet gas or liquids to minimize potential emissions of $SO_2$ and maintain engine components for proper operation. Certain lean burn engines under 500 hp firing sour gas are used in the field and, if these engines meet subsection (1), Table 9 and follow the BMP, they are authorized under the PBR. 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 (additional details can be found in the Air Quality Standard Permit for Oil and Gas Sites technical summary). The commission also notes that the proposed PBR 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 commission proposes subsection (e)(5) to ensure that fugitive emissions from open-topped tanks or ponds are accounted for. Currently, open-topped tanks and ponds are authorized and found to be integral in site operations. While the amount of hydrocarbon liquids entrained in open-topped tanks and ponds may be minimal, the amount of VOCs and $H_2S$ emissions from these sources can be substantial. This is due to the open-topped tank or pond being exposed to the evaporative effects of the sun and wind. Therefore, VOCs or $H_2S$ emissions from open-topped tanks or ponds are allowed up to a potential to emit equal to 1 tpy of VOC or 0.1 tpy of $H_2S$.

The commission proposes subsection (e)(6) to ensure that fugitive components, including those from enclosed tanks, are kept in good working condition and are not found to be leaking liquids or gases. The proposed rule requires open-ended valves or lines to be equipped with a cap, blind flange, plug, or a second valve to seal the line to ensure that no leakage of emissions occurs. Additionally, all seals and gaskets in VOC or $H_2S$ service shall be installed, checked, and properly maintained in order to prevent leaking. Furthermore, the commission is requiring tank hatches to be gasketed and remain in the closed position, but not necessarily completely locked down, to ensure that the tanks vapors are not freely allowed to escape through open gaps in the tank or tank's gaskets or seals. Lastly, hatches, valves, and lines integral to operations within the tank must be allowed to vent in order to prevent an excess pressure build-up within the tank and ensure the conditions within the tank are not hazardous. Therefore, some fugitive emissions must be allowed to escape from the tank. For this reason the use of a VRU would be highly recommended in preventing the loss of valuable and useful product. In addition to recovering product, this would help to ensure site-wide protectiveness.

The commission proposes subsection (e)(7) to ensure that new and replaced fugitive components in gas or liquid service will comply with the appropriate fugitive monitoring program. However, this monitoring program only applies to fugitive components at sites which are not otherwise subject to NSPS KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants, or voluntarily implementing a leak detection and repair (LDAR) program. The proposed rule requires fugitive components to be inspected periodically, and leaking components repaired. Basic fugitive monitoring is an important part of the proposed PBR. In some cases, there have been reports of open-ended pipes and seriously leaking components at OGS, thus raising concerns over unaccounted for emission releases. Concern over components which may need repair or replacement is addressed by the executive director's current consideration to specify BMP for fugitive components at OGS with estimated uncontrolled potential to emit equal to or greater than 10 tpy VOC or 1 tpy $H_2S$. At a minimum, the commission would prohibit open-ended piping, at least yearly visual and olfactory inspections, and monitoring with portable analyzer to identify leaking components and initiate repairs in a timely manner. The commission proposes a requirement for traditional portable analyzers to be used to find leaking components which need to be repaired. These portable analyzers are commonly available with well-established standards and guidelines. The owner or operator would be required to use EPA Method 21 to screen for leaking components with a portable analyzer. Method 21 is the EPA established methodology for performing leak detection screening with a portable analyzer.

Additionally, the EPA promulgated the Alternative Work Practice (AWP) on December 22, 2008 (73 *Federal Register* 78199) for using optical gas imaging instruments to find leaking components. The

AWP was promulgated in 40 CFR §60.18. Therefore, the proposed PBR would also allow the use of the AWP from 40 CFR §60.18(g) - (i) as an alternative to using portable analyzers to screen for leaking components in the BMP. The frequency of monitoring using the AWP for the proposed BMP fugitive emission monitoring requirements is at least once per year, which is less frequent than is required by 40 CFR §60.18. However, the frequency requirements in the federal AWP range from monthly to bimonthly which may be overly burdensome to sites that could be subject to the BMP, especially if the sites are unmanned. Specific parts of the EPA AWP have been excluded from the BMP. The annual Method 21 requirement in 40 CFR §60.18(h)(7) and the reporting requirement of the annual Method 21 results in 40 CFR §60.18(i)(5) are specifically excluded from the BMP because the use of the AWP is provided as an alternative to performing an annual Method 21 screening. Including these requirements in the BMP would make providing the AWP as an option meaningless. The owner or operator would be required to use EPA Method 21 to screen for leaking components with a portable analyzer. The commission invites comment on incorporating the final AWP requirements from 30 TAC Chapter 115, Control of Air Pollution from Volatile Organic Compounds, into the proposed PBR to establish a consistent approach for using optical gas imaging instruments and the AWP for finding leaking compounds. Additionally, the commission is considering adoption of an incentives program in Chapter 101, General Air Quality Rules, for the use of optical gas imaging cameras.

The optical gas imaging instruments, such as the GasFind Infrared (GasFindIR) camera, is a new tool that has become highly relied upon by various regulatory agencies and companies to help identify releases of air contaminants. While the camera cannot indicate what the chemical constituents of the stream are, or their quantity, it does provide an excellent indicator that some emissions are being released. While the technology is not capable of measurements, minimum detection limits have been estimated by the infrared camera manufacturers and EPA. Results vary dramatically due to the following factors: the relative temperatures of the gas under observation and the background; the relative infrared absorption coefficient of the specific gas or gases being observed; atmospheric conditions such as rain, fog or high humidity, wind, blown dust, etc.; the physical characteristics of the emissions themselves - volumetric flow, orifice size and location, presence of steam or PM; physical and thermal conditions at the site - distance from the camera, reflected and radiated heat, making by steam and PM, etc.; and operator dependent parameters such as use of temperature sensitivity range (high, mid, and low), manual or auto tune, High Sensitivity Mode if camera is so equipped, polarity, lens focal length (e.g., 25, 50, or 100 millimeter telephoto), age and condition of the camera's eyepiece, state of operator fatigue (optical and general), operator training, experience, and effort.

In light of the stated limitations, a reasonable estimate of the technology's current minimum detection limit (best conditions assumed) ranges from a 0.001 lb/hr to 0.22 lb/hr. The low end of this assessment is based on the manufacturer's estimates, while the high end is based on the expectations of the new EPA AWP. Variability is certain to occur, and additional information on the sensitivity of the device is available from the manufacturer and is based on the independent laboratory (third party) testing. The lower detection limit of the camera would include the presence of methane, ethane, and regulated VOC compounds. A summary of lower detection limits can be found at: h*ttp://www.tceq.state.tx.us/implementation/barnettshale/bshale-faq*.

The commission is also in the process of developing regulations which clarify and refine the federal AWP to improve practical enforceability by enhancing the quality assurance, records, and training requirements for LDAR rules in Chapter 115. The commission invites comment on incorporating the final AWP requirements from Chapter 115 into the proposed PBR to establish a consistent approach for using optical gas imaging instruments and the AWP for finding leaking compounds. Additionally, the commission is considering adoption of an incentives program in Chapter 101 for the use of optical gas imaging cameras. If adopted prior to this proposal, the changes from those rules will be incorporated in this package.

While LDAR BACT requires components to be repaired or replaced in 15 days, the executive director recognizes the potential remote location of OGS and has proposed 30 days for manned sites and 60 days for unmanned sites as a reasonable timeframe to fix leaking components. Also consistent with LDAR BACT, if the repair of a component 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. This flexibility helps prevent emission releases which may be of greater magnitude that is necessary. Finally, the proposed PBR requires new facility components to, whenever possible, be placed in such as way that future monitoring can be easily accomplished.

These requirements are proposed in order to address the potential of unintentional and inappropriate VOC and $H_2S$ emissions throughout the state as documented by the recent air monitoring in the Dallas area and the Texas Railroad Commission advisory. As an example, a typical OGS may have 1,000 fugitive components, and depending on the configuration and service, uncontrolled potential emissions may range up to 3 lb/hr and 15 tpy of VOC and 0.4 lbs/hr and 2 tpy for $H_2S$, assuming no open-ended pipes, open valves, or continually leaking seals and components. The occurrence of less than 1% of these components leaking or being open can result in emissions that could be less to several times more than the estimated uncontrolled potential emissions. The uncontrolled fugitive emissions are based upon "average" emissions factors for uncontrolled fugitive components from a zero leakage up to the 10,000 parts per million by volume (ppmv) VOC leak definition rate. The leakage rate for leaking components has no upper limits or emission factors for leaking fugitive components. This is not good engineering practice, and these emissions are not accounted for protectiveness evaluations.

Based on initial stakeholder requests, the commission has reviewed the potential effectiveness of this fugitive monitoring program. The frequency of monitoring and observations and specified repair and replacement of leaking components is expected to reduce releases of VOC and $H_2S$. While not as diligent and stringent as established LDAR programs which are credited with 75 - 98% control of fugitive emissions, this program is expected to reduce emissions by a possible range of 20 - 40%. The commission is further evaluating the appropriate quantification of credit for this requirement and is seeking comment. This credit may be taken by companies when following all requirements for the BMP in the proposed section and calculating emissions for a given OGS.

The commission proposes subsection (f) to address additional requirements, which are specific to certain facilities and provide allowable control efficiencies for add on control devices. In response to industry comments that the PBR is for insignificant emissions and the commission should not be mandating BACT for these facilities, the commission concurs in part and clarifies that in cases when process or add-on control is not necessary for showing compliance with emission limits, control and detailed monitoring requirements are not required. The effective and efficient use of control at an OGS can also make the site's emission impact potential insignificant allowing a site needing add-on control to use the PBR; but the effectiveness of the control becomes critical so the application of the additional requirements, sampling, monitoring, and records is mandatory where the control is necessary.

If an OGS can show the uncontrolled emission potential from all the sources at the site would be compliant with the emission limitations without control, they are not subject to these additional requirements. Control can be used at the OGS even if it is not required, and where the control is not required the control efficiency and monitoring requirements for the control do not apply. Note, where combustion control is not required but is employed the criteria pollutant products of combustion (not including the VOC) in addition to the potential uncontrolled (assuming the control device is not present) air contaminants, such as VOC, benzene, and $H_2S$, must be evaluated for maximum allowable emission rates.

The control and add-on control devices considered for additional requirements include tank color, condensers on glycol dehydrator units, reboilers and heaters or furnaces used for VOC control in addition to their normal heat delivery function, VRUs, flares and thermal oxidation and vapor combustion control devices. These are the common methods employed to effectively control the emissions from the facilities this PBR is authorizing. The commission requests details on the operation and maintenance of any other devices that are currently commonly used that have not been considered. The facilities authorized (eg. tanks, tanks with flash, separators, truck loading, amine units, etc. with vents) have an uncontrolled potential to emit established by the rate and make up of the material they are processing or handling, and the pressure and temperature at which the facilities are operating. This PBR requires that these parameters and rates be estimated for the worst-case to establish if they meet emission limits for this PBR and maintain records to show that the continued operation is in compliance. If those emissions meet the emission limits for this PBR, control is not necessary for the site to be considered insignificant. Where control is necessary to be compliant, the control device efficiency becomes critical and must be supported. The commission has considered the potential efficiency of add-on control devices and is proposing to allow applicants to claim and support an efficiency that ensures emission limit compliant operation. The commission proposes to allow claims of efficiency for properly maintained and operated devices that it believes are most certain with a minimal amount of monitoring that indicates proper operation. The commission recognizes that these devices can be even more efficient and will allow companies to claim higher efficiencies where there is a need to meet the emission limits for the PBR or when the applicant is willing to support the claims with more rigorous enhanced monitoring or testing.

The commission proposes subsection (f)(1) to require all tanks, process vessels, temporary liquid storage tanks containing VOC and $H_2S$ to be operated within design requirements and painted a color that minimizes the effects of solar heating with a solar absorbance factor of 0.43 or less. While the argument can be made that rust falls within the approved solar absorbance factor, rust does not constitute an approved design requirement. Therefore, tanks with rust are expressly excluded from approved solar absorbency colors. 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 $H_2S$ emissions when a tank was red (or rust). In a typical tank example, this could be a potential release 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 losses. 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 state-wide 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 $H_2S$ 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 all permanent and temporary liquid and gas tanks and vessels. However, for tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor these requirements do not apply. Furthermore, 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 and or aesthetics. Lastly, for tanks or vessels in an area whereby a local, state, federal law, ordinance, or private contract predating this section's effective date establishes in writing tank and vessel colors other than white, these requirements do not apply.

The commission proposes in subsection (f)(2) to allow condensers designed with glycol dehydration systems that condense the boiled off water and VOCs to claim up to 80% control of the VOCs reaching the condenser. The dehydrators are a common facility at OGS and have the potential for high hourly emissions of benzene, toluene, ethylbenzenes, and xylenes (BTEX). With an efficient condenser design the water and organic vapors can be condensed and be captured, but the commission fears they are often ineffective due to non-saturated vapor conditions, varying coolant temperature control and carry out due to high vapor velocity or ineffective droplet capture, so a maximum of only 80% is allowed with basic monitoring. Basic monitoring for condensers in subsection (1), Table 8 is the vapor exhaust temperature that controls the assumed saturation point for the control. For a greater efficiency, stack testing would need to be conducted to prove the efficiency at the desired operating flow conditions into and out of the condenser for various dehydrator operating scenarios which would then also need to be monitored. Note the exhaust on glycol dehydrator unit condensers may also be directed to control, like the reboiler, a flare, other oxidizer, or other control unit and efficiencies may be combined for emission control if desired or needed. This would trigger the monitoring for both controls. However, if no control is claimed for the condenser and all of the exhaust gas can be handled by the next device without the condenser control, the basic monitoring is not required.

The commission proposes subsection (f)(3) to address the add-on control function of process reboilers, heaters, or furnaces that are also used to control waste gas streams and will allow efficiencies up to 90% or 99% with basic monitoring depending on the design. Where a waste stream vent can be mixed directly with the device's primary fuel and then fired through the engineered burner, the commission is confident that the device will burn efficiently as designed, and allow up to a 99% destruction claim with basic monitoring. Additional confidence is based on the applicant's dependence on the proper efficient function of the reboiler or heater to run the process properly so inefficient or inconsistent combustion could impact their product. There is less confidence where the waste gas enters the fire box separately or with the combustion air, but the streams commonly burned in this fashion can be very combustible so a claim of up to 90% destruction can be made with basic monitoring. Obviously streams with high concentrations of carbon dioxide or nitrogen would garner concern in how effectively the combustible constituents can mix and burn, but where long residence times and high temperatures are reached, destruction can be much better than 90% and the commission proposes to allow up to 99% destruction where enhanced monitoring ensures effective combustion is occurring. A substantial concern regarding the use of process equipment for the secondary purpose of control is full control efficiency on line time. A common use of control with a reboiler/heater is for a flash tank on glycol dehydrators and some amine units, but where the flash tank is emitting continuously the reboiler can be cycling and low firing to maintain temperature. Enhanced monitoring is appropriate to confirm control and assess emissions when control is not occurring. Proposed basic monitoring is flexible and can be any continuous monitor that indicates there is a flame, including fire box temperature, rising or steady process temperature, CO monitoring, primary fuel flow, fire box pressure or equivalent. Enhanced monitoring needs to be direct on the combustion and include continuous fire box temperature, CO and oxygen monitoring with at least six minute concentration averages recorded. Enhanced monitoring where the control device can cycle off or to low firing or the waste stream can by-pass the device must include a continuous disposition of the waste gas stream in concert with the devices combustion status. Specifically, when monitoring the waste gas stream, the flow or the valve position to any potential by-pass must be continuously monitored and recorded, so the OGS can show all the waste gas stream was directed to a fully effective control.

Two common control systems used at OGS are VRUs and thermal destruction units. In proposed subsection (f)(4) 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 tanks. The switch detects pressure variations inside the tanks 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 tanks, and the vapor recovered is pumped into gas sales lines. Properly maintained, appropriately sized, designed, and operated VRUs can achieve 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 units to handle the maximum volume typically expected from vessels being controlled. 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 American Petroleum Institute gravity, tank operating characteristics (e.g. flow rate, size of tank), and ambient temperature. This information is important in order to determine the exact changes occurring before, during, and after fluids are added to the tank. Additionally, this information can be found in the latest Exploration and Production (E&P) Tanks 2.0 program if applicants wish to utilize it.

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 will not only reduce the generation of emissions, but may also provide potential reductions in subsequent control design requirements (e.g., size) and costs. When the VRU is down for maintenance (historically represented as equal to or less than 5% of the year or 430 hours), tank and vessel emissions are typically released to the atmosphere uncontrolled. These emissions must be considered for appropriate limits for protectiveness and may require routing to another control device.

Thermal destruction units used at OGS include flares, thermal oxidizers, and vapor combustors. Proposed subsection (f)(5) addresses the use of flares at an OGS. One of the most common add-on control devices is the basic candlestick flare and the commission will continue to allow the use of a properly designed and operated flares for normal emission control with an assumed destruction efficiency of 98% with basic pilot flame or ignition monitoring. The key elements of the commission's acceptance are in the design that insures the waste gas flow to the flare continuously meets the minimum heating value and maximum tip velocity as specified in 40 CFR §60.18, and compliance records that clarify how this is achieved. The proposed rule clarifies that sufficient fuel gas should be added as necessary to make the gas adequately combustible, which means the heating value meets 40 CFR §60.18 at all times waste gas is flowing. Flares, in accordance with 40 CFR §60.18, must also have a constant pilot flame to ignite the waste gas stream when it passes through the flare tip(s), and this is insured through the basic continuous monitoring of the pilot flames with thermocouple(s) or equivalent infrared monitor(s). The commission will allow automatic igniters like continuous sparking devices in lieu of a pilot flame, but for all flares records of the time, date, and duration of loss of the flare flame pilot flame must be recorded. The commission is also proposing to allow temporary, portable, and backup flares that operate less the 480 hours per year to not be subject to the monitoring requirements. The design of course must show the flare will receive an efficiently combustible stream which would meet 40 CFR §60.18 for heating value and maximum tip velocity at all times the waste gas is flowing. The expectation is that the unique infrequent operation will generally be associated with personnel present to insure proper operation and a flame during these events. Flare systems that cannot meet the basic 40 CFR §60.18 at all times when waste gas is flowing, cannot be authorized for control with the PBR.

Thermal oxidation and vapor combustion control devices are proposed for allowable control in subsection (f)(6). There is a wide variety of designs for this type of control ranging from simple partial enclosure of a flare tip to a fully enclosed ceramic heat retaining fire box with automated fuel and air control matched to the waste gas stream to maximize destruction. When properly designed and operated, the commission believes efficiencies from 90% to 99.9% can be effectively achieved. Any design where the applicant documents their devices expected efficiency with the variability of the waste gas streams to be controlled may claim up to 90% efficiency with any basic monitoring. Basic monitoring is a thermocouple or infrared monitor that indicates the device is working with a method of noting the hours of use. Devices may be shown to be efficiently designed using the principles of a combustible waste gas stream, with documentation showing the device will meet the requirements of 40 CFR §60.18 for the variability of the waste stream, or designed utilizing an engineered fire box that will hold the waste gas at greater than 1,400 degrees F for more than 0.5 seconds. These approaches may claim up to 98% destruction efficiency with intermediate monitoring. Intermediate monitoring is simply the continuous monitoring and recording of the exhaust temperature to insure the device is working at all times when waste gas is directed to the device, and the monitoring must show compliance with the 1,400 degrees F when applicable. The fire box or fire tube designs maintaining temperatures of 1,400 degrees F for more than 0.5 seconds may claim up to 99% if enhanced monitoring is utilized and the device is designed with ports and platforms to allow stack testing. Enhanced monitoring requires the addition of a continuous oxygen or CO monitor and waste gas flow indicator in addition to the temperature monitor on the exhaust that will record at least 6 minute averages and show the device is within the design oxygen range or CO is less than 100 ppmv when waste gas is flowing. The commission recognizes that some devices with some waste gas streams can operate more efficiently than noted above or be reasonably efficient at lower temperatures with shorter residence times. Destruction efficiencies up to 99.9% with enhanced monitoring and stack testing, and alternate temperatures and residence times may be established through stack testing.

The commission proposes subsection (g) to establish the criteria for Level 1 Post-Construction Registration of the PBR. Any OGS meeting these requirements must register with the commission no later than 180 days or 90 days, depending on emissions, after start of operations. The commission will establish a form and process through the E-permitting system of the agency. Paper forms or mailings will not be generated by this requirement. Along with the registration, companies would be required to 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 of estimating emissions. This requirement gives flexibility to industry in timing, but ensures that the executive director has the opportunity to audit emission estimates within a reasonable period of time from start of operation. Level 1 of the proposed PBR is intended to require minimal delay in processing paperwork, corresponding to the limited amount of emissions released by the OGS.

Proposed subsection (g)(1) does not allow this, or any, level of the PBR to be used if the emissions are considered to be a major source or major modification for purposes of PSD or NNSR. This level also prohibits OGS from being considered major for the federal operating permit program. This requirement establishes clear minor source status through the rule.

Proposed subsection (g)(2) covers the smallest of OGS and allows registration up to 180 days after well completion, start of operation, or implemented changes. These OGS are expected to be the simplest and have the smallest potential emissions. To ensure the lower potential, the site is limited to only fugitive components, separators, engines, tanks, and associated control devices, but not treatment units. Additionally, the OGS is limited to specific emission limits. The limits established on an hourly and annual basis for various pollutants should allow typical initial production (wellheads, pump jacks, etc), metering stations, and small unmanned locations to be authorized for production and planned MSS and not delay construction or operation of these small sites throughout Texas.

The proposed annual limit on VOC assures minor source status. The hourly limit for VOC is sufficient enough to allow low volume, sporadic, or well-controlled truck loading and blowdowns. The most substantial hourly sources of VOCs at OGS, based on a search in over 100 PBR registrations, are from uncontrolled crude oil or condensate truck loading. Uncontrolled emissions from truck loading also have the greatest potential impacts based on an evaluation for all the impacts tables. The commission reviewed an average 3 weight-percent benzene content in condensate or crude oil for truck loading at 1,400 feet for a conservative impacts evaluation. Based on this review, the commission determined an acceptable value for site-wide emissions of total VOCs could be approximately 25 lb/hr and thus this amount is proposed to be the hourly limit under proposed subsection (g)(2). A total of 97 data points were found for truck loading yielding an average of 27.01 lb/hr for truck loading emissions and a range from 0.32 lb/hr to 119.41 lb/hr. Therefore, the proposed 25 lb/hr VOC is reasonable for small OGS. Site-wide hourly emission rate includes VOC emissions from engine, turbines, and other combustion devices. Emissions of benzene, toluene, and xylene from engines, turbines, and other combustion sources are not expected to be significant contributors to overall site-wide emissions because most of the potential emissions are destroyed due to combustion.

The benzene limits proposed in subsection (g)(2) are based on an evaluation of the hourly and annual ESLs (170 $\mu g/m^3$ and 4.5 $\mu g/m^3$), typical expected benzene concentrations (3%), allow for truck loading and blowdowns, and be protective based on the conservative impact tables. Evaluation of the impacts tables shows 0.82 lb/hr and 1.19 tpy of benzene is protective at approximately 1/4 mile. Therefore the proposed 0.8 lb/hr and 1.2 tpy for benzene are reasonable for small OGS. Toluene has a 1-hour ESL of 640 $\mu g/m^3$ and annual ESL of 1,200 $\mu g/m^3$. The annual ESL is not the limiting factor for emissions impacts. Based on the impact tables, truck loading at 1,400 feet from the nearest receptor was also used to determine maximum allowable site-wide hourly emissions of toluene at approximately 3.1 lb/hr. Xylene has a 1-hr ESL of 350 $\mu g/m^3$and annual ESL of 180 $\mu g/m^3$. Using the impacts tables, truck loading at 1,400 feet from the nearest receptor was also used to determine maximum allowable site-wide hourly emissions of xylene to be 1.7 lb/hr.

$H_2S$ emissions are limited to 0.5 lb/hr and 2.2 tpy. These limits are based on the previously discussed ambient air standard compliance assurance. The hourly limit of 0.5 lb/hr was chosen using the evaluation above. Since hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 0.07 lb/hr with a range of 0.01 lb/hr to 0.62 lb/hr $H_2S$ emissions from both sweet and sour OGS, this limit is reasonable for small OGS. The annual limit of 2.2 tpy was chosen because it is an annualized amount based on the 0.5 lb/hr. Additionally, the commission needs to be assured that the OGS will not cause or contribute to an odor nuisance which is likely to result from highly sour uncontrolled sites. The $H_2S$ hourly and annual limits should ensure that the state ambient standards are met for most sites, and yet still allow slightly sour materials to be handled as well as low volume, sporadic, or well-controlled truck loading and blowdowns.

$SO_2$ emissions are limited to 5.4 lb/hr and 10 tpy. These limits are based on the previously discussed ambient air standard compliance assurance. The hourly limit of 5.4 lb/hr was chosen using the evaluation above. This limit is reasonable for a small OGS. A random audit of approximately 100 reviewed OGS

PBR registrations in 2010 showed the range of $SO_2$ emissions for sour sites to be 35 lb/hr to 40 lb/hr, with an average of 37 lb/hr and the range of $SO_2$ emissions for sweet sites to be 0.01 lb/hr to 6.30 lb/hr, with an average of 4.25 lb/hr. The limitations on hourly $SO_2$ would allow both typical releases from engines as well as any moderately sour waste steams to be burned in a flare. Since there are no treatment units allowed under this level of the PBR, high hourly $SO_2$ emissions from amine units do not have to be considered. The annual limit of 10 tpy was chosen as a reasonable cut off for the amount of $SO_2$ expected to be seen at sites under this level.

$NO_X$ emissions are limited to 9 lb/hr and 25 tpy. These limits are based on the previously discussed NAAQS compliance assurance and should be sufficient to allow a limited number of compressor engines or electric generators to operate at a site. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 4 lb/hr with a range of 0.36 lb/hr to 19 lb/hr for engines. The commission would not expect demonstration of impacts for any engine or combustion source to be needed at less than 9 lb/hr using the evaluation above. Based on review of engine designs, it has been found that engines greater than 1,000 hp have the potential for the greatest source of $NO_X$ emissions compared to engines less than 1,000 hp. Furthermore, it has been determined by evaluation of OGS that smaller sites would most likely operate engines less than 1,000 hp. The commission is proposing 25 tpy of $NO_X$ to assure minor source status with respect to NNSR. This limit would cover any potential site in the most severe nonattainment areas designated in Texas. Therefore the proposed 9 lb/hr $NO_X$ and 25 tpy $NO_X$ limits are NAAQS compliant and should allow for both small and large engines at an OGS.

CO emissions are limited to 11.4 lb/hr and 50 tpy. These limits are based on the previously discussed NAAQS compliance assurance and should be sufficient to allow a limited number of compressor engines to operate at a site. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 4 lb/hr with a range of 0.03 lb/hr to 14 lb/hr for engines. The commission would not expect demonstration of impacts for any engine or combustion source to be needed at less than 14 lb/hr using the evaluation above. Based on review of engine designs, it has been found that engines greater than 1,000 hp have the potential for the greatest source of CO emissions compared to engines less than 1,000 hp. Furthermore, it has been determined by evaluation of OGS that smaller sites would most likely operate engines less than 1,000 hp. The commission is proposing 50 tpy of CO with an equivalent hourly rate of 11.4 lb/hr, assuming steady-state, and continuous releases from combustion sources. The proposed 11.4 lb/hr CO and 50 tpy CO limits are NAAQS compliant and should allow for both small and large engines at an OGS.

After a random audit of approximately 100 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, and annual emissions 0.01 tpy to 0.57 tpy. Using the most conservative impacts table, the smallest acceptable $PM_{2.5}$ emission rate could be as high as 1.45 lb/hr. Based on this information, it is extremely unlikely that any OGS will have or contribute to an exceedance of the $PM_{10}$ or $PM_{2.5}$ NAAQS. The commission proposes a limit of 0.5 tpy $PM_{10}$ and $PM_{2.5}$ as a limit for the smallest sites.

Formaldehyde emissions are limited to 0.90 lb/hr. This limit is based on the previously discussed ESL compliance assurance and should be sufficient to allow a limited number of compressor engines to operate at a site. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 0.28 lb/hr with a range of 0.01 lb/hr to 0.74 lb/hr for engines. The commission is proposing 0.90 lb/hr, which should allow for both small and large engines at an OGS.

Proposed subsection (g)(3) establishes conditions which require registration of facilities within 90 days after well completion, start of operation, or implemented changes. While these OGS would also be required to be smaller in order to delay registration requirements, there are no stipulated limits on the types of facilities which could be at these sites. A great variety of equipment is covered under this level of the PBR (wellheads, separators, heater treaters, tanks, vapor recovery units/other recovery methods, compressors/engines, fugitives/piping, methanol used in piping, and loading equipment). This level of the PBR is intended to give an incentive (post operational, not preconstruction registration or certification) to an OGS which is inherently small or install VRUs or use other methods to substantially minimize emissions. The limits proposed establish a boundary for any site's potential to emit and eliminates the need for any certification. The 10 tpy VOC limit ensures that the site cannot have 10 tpy of any individual hazardous air pollutant (HAP). In combination with the emission requirements based on the protectiveness review, this limit also ensures that 40 CFR, Part 63, Subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, cannot be applicable. Therefore, an OGS under this level of the PBR will not be expected to submit a federally enforceable emissions certification, further minimizing paperwork requirements.

The proposed annual limit of 10 tpy for total VOC continues to assure minor source status. The hourly limit for VOC is sufficient enough to allow sporatic or well-controlled truck loading and blowdowns. Although benzene and other HAPs are used as surrogates for demonstrating total VOC emissions are acceptable, the commission also evaluated the maximum condensate or crude oil emissions allowed under the impacts tables. At 1,800 feet, using the loading fugitives or blowdown dispersion characteristics, total VOC emissions could be 50 lb/hr. Since the actual emissions from an OGS will result from a combination of sources, many with more effective dispersion, this value was determined by the commission to be an appropriate limit for this subsection. This value is also in the typical ranges of hourly emissions from a random sampling of PBR registrations in 2010. From the registrations reviewed, total VOCs averaged 27 lb/hr for truck loading emissions and ranged from 0.32 lb/hr to 119.41 lb/hr. Therefore, the proposed 50 lb/hr VOC is reasonable for small OGS.

The benzene limits are based on an evaluation of expected benzene concentrations (3%), the impacts tables, and allow for truck loading and blowdowns. Based on the commission's evaluation, the truck loading and blowdown releases result in the highest peak emissions, as well as the most conservative dispersion characteristics. At 1,500 feet, the acceptable benzene emissions would be 1.82 lb/hr and 2.64 tpy using the appropriate ESLs. Based on the average concentration of benzene in the VOC streams at an OGS, the typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 gives an average range of 0.81 lb/hr for truck loading emissions, with a range from 0.01 lb/hr to 3.5 lb/hr. Therefore, the proposed 1.8 lb/hr and 2.5 tpy for benzene is reasonable for small OGS.

At the same sources, toluene and xylene were evaluated by the commission. At 2,200 feet, the acceptable toluene emissions would be 6.37 lb/hr and 3.48 lb/hr, respectively. The typical ranges of hourly emissions from a random sampling of standard permit registrations in 2010 gives an average ranges of toluene and xylene, with 0.08 lb/hr and 0.06 lb/hr, respectively. Therefore, the proposed 6 lb/hr for toluene and 3 lb/hr for xylene is reasonable for small OGS.

Formaldehyde emissions are limited to 1.5 lb/hr. This limit is based on the previously discussed ESL compliance assurance and should be sufficient to allow a limited number of compressor engines to operate at a site. At 2,200 feet, the acceptable emissions would be 1.51 lb/hr. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 0.28 lb/hr with a range of 0.01 lb/hr to 0.74 lb/hr for engines. The commission's proposal should allow for both small and large engines at an OGS, as well as protectiveness.

$H_2S$ emissions are limited to 2 lb/hr and 4.5 tpy. These limits are based on the previously discussed ambient air standard compliance assurance. The hourly limit was chosen because 2 lb/hr would meet the most stringent state ambient air standard, based on the impacts tables at 1,600 feet with a 20-foot stack. The annual limit of 4.5 tpy was chosen as two times the previous level's hourly limit as opposed to annualizing the 2 lb/hr hourly limit, because the hourly is meant to account for MSS emissions which are infrequent and of short duration. Additionally, the commission is developing this authorization and needs to be assured that the OGS will not cause or contribute to an odor nuisance which is likely to result from highly sour uncontrolled sites.

$SO_2$ emissions are limited to 8 lb/hr and 15 tpy. These limits are based on the previously discussed ambient air standard compliance assurance. The hourly limit was chosen because 8 lb/hr would meet the most stringent ambient air standard, based on the impacts tables at 2,200 feet with a 20-foot stack. The annual limit of 15 tpy was chosen as a reasonable cut-off for the amount of $SO_2$ expected to be seen at sites under this level. The commission purposely chose to have higher hourly limits than what they would be by converting the annual limits to hourly based on continuous release, and to allow for high hourly peaks.

$NO_X$ emissions are limited to 25 lb/hr and 100 tpy. These limits are based on the previously discussed

NAAQS compliance assurance and should be sufficient to allow a limited number of compressor engines or electric generators to operate at a site. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 4 lb/hr with a range of 0.36 lb/hr to 19 lb/hr for engines. The commission expects most engines for sites in this category to be 1,000 hp or more and based on the impacts tables at 800 feet with an 8 foot stack $NO_2$ emissions from engines would comply with the new NAAQS. Furthermore, the commission is proposing 100 tpy of $NO_X$ to assure minor source status with respect to Title V.

CO emissions are limited to 22.8 lb/hr and 100 tpy. These limits are based on the previously discussed NAAQS compliance assurance and should be sufficient to allow a limited number of compressor engines to operate at a site. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 4 lb/hr with a range of 0.03 lb/hr to 14 lb/hr for engines. The commission would not expect demonstration of impacts for any engine or combustion source to be needed at less than 14 lb/hr using the evaluation above. Based on review of engine designs, it has been found that engines greater than 1,000 hp have the potential for the greatest source of CO emissions compared to engines less than 1,000 hp. Furthermore, it has been determined by evaluation of OGS that smaller sites would most likely operate engines less than 1,000 hp. The commission is proposing 100 tpy of CO with an equivalent hourly rate of 22.8 lb/hr, assuming steady-state, and continuous releases from combustion sources. The proposed limits are NAAQS compliant and should allow for both small and large engines at an OGS.

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, and annual emissions 0.01 tpy to 0.57 tpy. Using the most conservative impacts table, the smallest acceptable

$PM_{2.5}$ emission rate could be as high as 1.45 lb/hr, with a corresponding acceptable limit of over 6 tpy. Based on this information, it is extremely unlikely that any OGS will have or contribute to an exceedance of the $PM_{10}$ or $PM_{2.5}$ NAAQS. The commission proposes a limit of 1.0 tpy $PM_{10}$ and $PM_{2.5}$ as a limit for these sites.

Proposed subsection (g)(4) establishes Level 1 registration procedures, forms, and methods of submittal, especially E-permits. The proposal also includes a list of expectations of information to accompany the registration information to ensure a complete public record and opportunity for commission audit. Subsection (g)(4)(C) establishes fees associated with hard-copy application submittals for the proposed Level 1 Post-Construction Registration. Per the provisions of §106.50, Registration Fees for Permits by Rule, registrants who submit a PBR registration for review by the commission on or after November 1, 2002 shall remit one of the following fees with the PI-7 registration form: $100 for small businesses, as defined in Texas Government Code, §2006.001, Definitions; non-profit organizations; municipalities; counties; and independent school districts with populations or districts of 10,000 or fewer residents, according to the most recently published census; or $450 for all other entities. Although various comments on fees were submitted by stakeholders, the commission is not proposing to increase the fees as a part of this action.

THSC, §382.062 establishes the fees that may be charged for various applications to the commission. The statute states that the fee may not be less than $25 or more than $75,000. This statute does not set out specific fees for PBRs, but states that commission may adopt rules relating to charging and collecting fees for PBRs. Thus, the commission has adopted rules relating to fees for PBRs which may be found at §106.50. Increasing the fees for the oil and gas PBR (and corresponding standard permit) and using these fees to create a fund to address any harm caused by the facilities is outside the scope of this rulemaking. The purpose of this particular rulemaking is to update the PBR (and corresponding standard permit) to reflect current science and available emissions information.

In this proposal, the commission is providing for a reduction in the fee for those registrants who submit their registration by E-permitting. Texas Water Code, §5.128, Electronic Reporting to Commission; Electronic Transmission of Information by Commission; Reduction of Duplicate Reporting, specifically allows the commission "to adjust fees as necessary to encourage electronic reporting and the use of the commission's electronic document receiving system." The reason for the reduced fee for submitting registrations through the E-permitting system is that filing electronically saves the commission an enormous amount of time and resources. Other than what is specifically authorized by law, in order to change fees for registrants claiming this PBR, the commission would have to undergo a rulemaking to revise the provisions found in §106.50.

The commission proposes subsection (h) to establish Level 2 Preconstruction Registration of the PBR to cover an OGS that could not meet Level 1, but is still considered to have insignificant emissions. Companies claiming Level 2 of the proposed section 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 slightly 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, updated emission estimates are required 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.

Proposed subsection (h)(1) limits the overall emissions for this level of the PBR to ensure there are no major PSD or NNSR sources (including any major plant turnarounds and all planned MSS). The level of the PBR would allow sites which are major for the federal operating permit program (greater than 100 tpy $NO_X$ or CO) the ability to use Oil and Gas General Operating Permits Numbers 511-514. Both sweet and sour OGS may use this level of PBR, but sulfur emissions are limited by the emission impact tables as applicable to the site.

The commission proposes subsection (h)(2) to establish emission thresholds that would require registration and approval for this section prior to construction. The proposed annual limit on VOC continues to assure minor source status and is the maximum allowed under this PBR.

The proposed annual limit of 25 tpy for total VOC continues to assure minor source status and is the maximum allowed under PBR. The hourly limit for VOC is sufficient enough to allow sporatic or well-controlled truck loading and blowdowns. Although benzene and other HAPs being used as surrogates for demonstrating total VOC emissions are acceptable, the commission also evaluated the maximum condensate or crude oil emissions allowed under the impacts tables. At 2,300 feet, using either the loading fugitives or blowdown dispersion characteristics, total VOC emissions could be 74.86 lb/hr. Since the actual emissions from an OGS will result from a combination of sources, many with more effective dispersion, this value was determined by the commission to be an appropriate limit for this subsection. This value is also in the typical ranges of hourly emissions from a random sampling of PBR registrations in 2010. From the registrations reviewed, total VOCs averaged 27 lb/hr for truck loading emissions and ranged from 0.32 lb/hr to 119.41 lb/hr. Therefore the proposed 75 lb/hr VOC is reasonable for small OGS.

The benzene limits are based on an evaluation of expected benzene concentrations (3%), the impacts tables, and allow for truck loading and blowdowns. Based on the commission's evaluation, the truck loading and blowdowns result in the highest peak releases, as well as the most conservative dispersion characteristics. At 1,800 feet, the acceptable benzene emissions would be 2.44 lb/hr and 3.54 tpy using the appropriate ESLs. Based on the average concentration of benzene in the VOC streams at an OGS, the typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 gives an average range of 0.81 lb/hr for truck loading emissions, with a range from 0.01 lb/hr to 3.5 lb/hr. Therefore, the proposed 2.25 lb/hr and 3.5 tpy for benzene is reasonable for small OGS.

At the same sources, toluene and xylene were evaluated by the commission. At 2,400 feet, the acceptable toluene emissions would be 7.31 lb/hr and 3.998 lb/hr, respectively. The typical ranges of hourly emissions from a random sampling of standard permit registrations in 2010 gives an average ranges of toluene and xylene, with 0.08 lb/hr and 0.06 lb/hr, respectively. Therefore, the proposed 7 lb/hr for toluene and 4 lb/hr for xylene is reasonable for small OGS.

Formaldehyde emissions are limited to 2.0 lb/hr. This limit is based on the previously discussed ESL compliance assurance and should be sufficient to allow a limited number of compressor engines to operate at a site. At 2,700 feet, with a stack height of 35 feet, the acceptable emissions would be 2.01

lb/hr. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 0.28 lb/hr with a range of 0.01 lb/hr to 0.74 lb/hr for engines. The commission's proposal should allow for both small and large engines at an OGS, as well as protectiveness.

$H_2S$ emissions are limited to 6 lb/hr and 9 tpy. These limits are based on the previously discussed ambient air standard compliance assurance and should be sufficient to allow a wider range of $H_2S$ sources at a site. The hourly limit of 6 lb/hr was chosen based on the impacts tables at 2,700 feet with a very tall stack, $H_2S$ emissions would comply with the applicable ambient standards. The annual limit of 9 tpy was chosen as two times the previous level's hourly limit as opposed to annualizing the 6 lb/hr hourly limit, because the hourly is meant to account for MSS emissions which are infrequent and of short duration. Additionally, the commission is developing this authorization and needs to be assured that the OGS will not cause or contribute to an odor nuisance which is likely to result from highly sour uncontrolled sites.

$SO_2$ emissions are limited to 12 lb/hr and 25 tpy. These limits are based on the previously discussed ambient air standard compliance assurance and should be sufficient to allow a wider range of $SO_2$ sources at a site. The hourly limit of 12 lb/hr was chosen based on the impacts tables at 2,700 feet with a very tall stack, $SO_2$ emissions would comply with the applicable ambient standards. The annual limit of 25 tpy was chosen to match with the limit set in §106.4, Requirements for Permitting by Rule.

$NO_X$ emissions are limited to 50 lb/hr and 250 tpy. These limits are based on the previously discussed NAAQS compliance assurance and should be sufficient to allow a wider range of compressor engines or electric generators to operate at a site. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 4 lb/hr with a range of 0.36 lb/hr to 19 lb/hr for engines.

The commission expects most engines for sites in this category to be 1,000 hp or more and based on the impacts tables at 2,300 feet with a very tall stack, $NO_2$ emissions from engines would comply with the new NAAQS. Furthermore, the commission is proposing 250 tpy of $NO_X$ to assure minor source status with respect to PSD.

CO emissions are limited to 57 lb/hr and 250 tpy. These limits are based on the previously discussed NAAQS compliance assurance and should be sufficient to allow a large variety of compressor engines to operate at a site. Typical ranges of hourly emissions from a random sampling of PBR registrations in 2010 showed an average of 4 lb/hr with a range of 0.03 lb/hr to 14 lb/hr for engines. The commission would not expect demonstration of impacts for any engine or combustion source to be needed at less than 14 lb/hr using the evaluation above. Based on review of engine designs, it has been found that engines greater than 1,000 hp have the potential for the greatest source of CO emissions compared to engines less than 1,000 hp. Furthermore, it has been determined by evaluation of OGS that smaller sites would most likely operate engines less than 1,000 hp. The commission is proposing 250 tpy of CO with an equivalent hourly rate of 57 lb/hr, assuming steady-state, continuous releases from combustion sources. The proposed limits are NAAQS compliant and should allow for both small and large engines at an OGS.

After a random audit of approximately 100 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 and annual emissions 0.01 tpy to 0.57 tpy. Using the most conservative impacts table, the smallest acceptable $PM_{2.5}$ emission rate could be as high as 1.45 lb/hr, with a corresponding acceptable limit of over 6 tpy. Based on this information, it is extremely unlikely that any OGS will have or contribute to an exceedance of the $PM_{10}$ or $PM_{2.5}$ NAAQS. The commission proposes a limit of 2.0 tpy $PM_{10}$ and $PM_{2.5}$ as a limit for these sites.

Subsection (h)(3) establishes specific scenarios where registrations must be certified. Subsection (h)(3)(A) addresses many sites throughout the state which are currently major and may have used some version of this PBR in the past, it is highly likely some small projects may occur under this PBR. The registration in that circumstance should be evaluated and all representations and limitations relied upon to ensure emission increases are less than any applicable threshold or contemporaneous emission increases have not and will not occur. Most registrations will include the commission's Core Date Form and PI-7 Form, with various attachments and supporting documentation. In some cases, sites may also need to submit a certified registration using Form PI-7-CERT. The circumstances which may require an OGS to certify include, but are not limited to, the following circumstances. For projects at existing major sites, §106.4(a)(1), establishes limits for production and planned MSS for each facility (piece of equipment) at 250 tpy for $NO_X$ and CO or 25 tpy VOC, PM, $SO_2$, and any other contaminant. However, these limits are greater than the triggers/thresholds for major sources or major modifications under NNSR or PSD, including but not limited to: 5 tpy VOC or $NO_X$ netting triggers for NNSR areas; 25 tpy, 50 tpy or 100 tpy $NO_X$ for nonattainment areas; 40 tpy or 100 tpy $NO_X$ anywhere for PSD; 100 tpy CO anywhere for PSD; 15 tpy $PM_{10}$ anywhere for PSD; and 10 tpy $PM_{2.5}$ anywhere for PSD.

For projects at existing major sites, specific PBRs for plants or facilities may have no emission limits or allow emissions greater than triggers or thresholds for major sources or major modifications under NNSR or PSD. Examples include, but are not limited to: §106.261 which allows 10 tpy of $NO_X$ or VOC, but amounts greater than 5 tpy VOC or $NO_X$ are the netting triggers for NNSR areas. If a project includes control technology, limited hours, throughput, and materials or other operational limitations which restrict

PTE, EPA guidance is clear that these limitations must be federally enforceable. Establishing certified limits ensures EPA and Texas that these emissions can be relied upon for federal permitting (PSD, NNSR, and Federal Clean Air Act, 112g) or federal standards (NSPS, NESHAP, MACT) applicability. Additional guidance memos on potential to emit may be found at *www.epa.gov/region07/programs/artd/air/policy/search.html*.

For projects at existing major sites, future-netting exercises for a site must rely on creditable increases or decreases. To be considered creditable, emission values must be federally enforceable. If not certified, future netting evaluations would have to rely on the facility potential to emit or Chapter 106 rule limitations, which would often result in inaccurate data and could potentially, affect the outcome of the netting evaluations. If a project is located at a site subject to $NO_X$ cap and trade requirements in Chapter 101, Subchapter H, Emissions Banking and Trading, the amount of $NO_X$ subject to that program must be federally enforceable. Certification establishes the basis for future compliance demonstrations and gives certainty to permit holders, regional investigators, permitting staff, and the general public. This is especially important for federal operating permit program compliance certifications and deviation reports. If a project is located at a site which has passed the deadlines in §101.222(h), the project must include planned MSS (even if emissions are zero) for determination of compliance with PBR rules (§106.4(a)(1) at a minimum).

For projects which resolve compliance issues, in many cases Regional Offices may request that PBRs be certified to ensure awareness of the requirements and expectations. The final proposed stipulation is for those operations relied upon to eliminate or minimize emissions which otherwise would occur from engine/compressor blowdowns. Since these representations are critical to having lower emissions, it is reasonable to require a commitment of enforceable limitations.

Proposed subsection (h)(4) outlines the processes and expectations for registration submittals reviews. To ensure a comprehensive public record, all supporting documentation to evaluate compliance with all applicable PBR requirements is needed with every registration. Due to the larger potential emissions from Level 2 OGS, the commission is proposing preconstruction registration and approval to ensure that these sites are properly accounting for all emissions and will be insignificant. The commission also proposes that all Level 2 OGS confirm registration assumptions by sampling all liquid and gas streams and any other necessary analysis or sampling. Once all this information is recorded, if emissions are greater than those previously registered or certified, a revised registration must be submitted within 180 days from start of operation. Subsection (h)(4)(E) establishes fees associated with hard-copy application submittals for the proposed Level 2 Pre-Construction Registration. Per the provisions of §106.50, registrants who submit a PBR registration for review by the commission on or after November 1, 2002 shall remit one of the following fees with the PI-7 registration form: $100 for small businesses, as defined in Texas Government Code, §2006.001; non-profit organizations; and municipalities, counties, and independent school districts with populations or districts of 10,000 or fewer residents, according to the most recently published census; or $450 for all other entities.

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 section is voluntary until January 5, 2012. For existing, properly authorized, OGS, MSS emissions do not need to be addressed until January 5, 2012, unless modifications are made. If modifications are made to an existing OGS on or after the applicable effective date of the proposed

PBR, 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 subsection (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. Paragraph (2) 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 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 PBR to reevaluate other MSS activities with negligible emissions.

Proposed subsection (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 98%, 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 PBR 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 PBRs, 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 Chapter 25, Environmental Testing Laboratory Accreditation and Certification. That does not mean all data must come from a NELAC certified lab. Rather, Chapter 25 explains when that certification must be applied. This requirement in the PBR is no more than what Chapter 25 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 $H_2S$, 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. PBRs are based on worst-case emissions and the potential to emit. Correct parameters are needed in order to verify that the site meets the PBR 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 $H_2S$. As needed and required by proposed subsection (j), 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 $H_2S$ 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 this section must demonstrate how they comply with the emission limitations of $H_2S$ by obtaining an analysis of the percentage/volume of $H_2S$ of the site. In order for a site to demonstrate that they meet the requirements of the $H_2S$ emission limitations of the PBR, one or more analyses 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 $H_2S$ concentration in the emissions to the air may increase many times from the incoming $H_2S$ liquid concentration to a tank during flash. At a minimum, if no computer program is used to estimate $H_2S$ flash emissions at a sour site, the pressurized flash sample taken for VOC should include an $H_2S$ analysis along with the daily production rate or sampling the $H_2S$ vent concentrations from a crude oil or condensate storage tank along with the estimated VOC tank emissions should be completed to estimate $H_2S$ flash emissions. Sour sites with produced water should calculate using some basis, sample, or use a computer program to estimate the produced water $H_2S$ emissions. It is expected that the $H_2S$ emissions be established for each facility in order to demonstrate compliance with the emission limitations. The commission continues to seek comments on $H_2S$ 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 depressured, 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, 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 $NO_X$ 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, oxygen and possibly $H_2S$ 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 ±10.55555 degrees F for 1,400 degrees F. 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 PBR 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, $H_2S$ 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 exchanger 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 solids 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.

Control device recordkeeping has been minimized for the PBR and BACT is not being mandated. The records for the control devices were minimized to indicators of performance for lower control expectations with more detailed and specific control for higher designed and claimed efficiencies necessary for the site to have insignificant emissions and meet the PBR emission limits.

For 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 CO 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 $NO_X$ 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 $H_2S$ is based on the fugitive column of subsection (1), Table 2 at 50 feet and is 0.025 lb/hr. The value for $SO_2$ is based on the 10 foot height process vent column of subsection (1), 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 $SO_2$ 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 subsection (1), 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 subsection (1), Table 2 at 50 feet and is 0.146 lb/hr. The value for xylene is based on the fugitive column of subsection (1), Table 2 at 50 feet and is 0.08 lb/hr.

Finally, in proposed subsection (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 impacts analysis; 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 2,700 feet.

Proposed subsection (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 PBR. The groups of similar emission releases were chosen based on similar parameters of the release points.

Subsection (1), 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, $E_{max}$ = P/G where $E_{max}$ 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, $E_{max}$ = ESL/G where $E_{max}$ 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 PBR, 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: $E_{max}$ (lb/hr) = (WR EPN 1) (P / G EPN 1) + (WR EPN 2) (P / G EPN 2) + (WR EPN 3) (P / G EPN 3) +…or $E_{max}$ (lb/hr) = (WR EPN 1) (ESL /G EPN 1) + (WR EPN 2) (ESL/G EPN 2) + (WR EPN 3) (ESL/G EPN 3) +…

With minor adjustments, this same equation can be used for annual impacts evaluation. Standard practice, as published in the TCEQ Modeling Guidance Document which may be found at *http://www.tceq.state.tx.us/permitting/air/guidance/newsourcereview/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: $E_{max}$ (tpy) = (8760/2000) ((WR EPN 1) (P / (0.08*G EPN 1)) + (WR EPN 2) (P / (0.08*G EPN 2)) + (WR EPN 3) (P / (0.08*G EPN 3)) +…or $E_{max}$ (tpy) = (8760/2000) ((WR EPN 1) (ESL /(0.08*G EPN 1)) + (WR EPN 2) (ESL/(0.08*G EPN 2)) + … where $E_{max}$ (lb/hr) = maximum hourly emissions acceptable (lb/hr); $E_{max}$ (tpy) = maximum tons per year emissions acceptable; WR 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 (($\mu g/m^3$)/(lb/hr)).

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 PBR. These emissions should be reviewed under the first column for "fugitive, loading, and tanks" in subsection (1), 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% 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 ($ft^3$/min or $m^3$/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 K; 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 ($v_s$) of 20 m/s and an effective stack gas exit temperature (Ts) 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 one-hour concentrations from SCREEN3 to averaging times greater than one-hour: three-hour multiply by 0.9; eight-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 -- 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 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: $M = (h_s\ V\ T_s)/Q$ 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; $V = (\pi/4)d^2v_s$ = 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 K; 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% 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 ($ft^3$/min or $m^3$/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 K; 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 K; 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*. 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*.

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 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 tables referenced throughout this section used for computation of emissions limits: 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; and Table 9 Engine and Turbine Emission and Operational Standards.

FISCAL NOTE: COSTS TO STATE AND LOCAL GOVERNMENT

Jeff Horvath, Analyst, Strategic Planning and Assessment Section, has determined that for the first five-year period the proposed rules are in effect, fiscal implications may be anticipated for the agency, but no fiscal implications are anticipated for other units of state or local government. The proposed rulemaking would repeal the PBR for oil and gas transportation and production facilities and propose a new PBR that is more protective of human health, requires consistency in facility authorization methods, and updates control technology requirements. If facilities are authorized under the repealed PBR and are not modified, they may continue to be authorized under the current PBR. If a facility is modified, it must be reauthorized under the new PBR or under the proposed Air Quality Standard Permit for Oil and Gas Production Facilities which is being revised concurrently.

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

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

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

*Implications for Agency Revenue*

Staff estimates that approximately 6,000 new and changing OGS will be required to submit a Level 1 post-construction registration ($50-$200) each year, and 3,000 new and changing OGS will be required to submit a Level 2 preconstruction registration ($100-450) each year. In the past, these OGS would not have required registration. In addition, staff estimates that 500 OGS currently operating under PBR will have to obtain a non-rule standard permit ($900). If a site currently operates under a PBR but has to obtain a new non-rule standard permit, the agency may see an increase in revenue. The estimated annual increase in revenue could be between $1,050,000 and $3,000,000 each year in Account 0151, Clean Air Account. Any increase in revenue would be offset by additional costs to various programs in the agency including Air Permits Division, Field Operations Division, E-Permits, and the Chief Engineers Office to implement the new requirements for the oil and gas industry. In comparison, over the last 2 years the commission has collected approximately $727,000 annually from PBR and standard permit registrations reviews from the oil and gas industry. Further, the commission has collected approximately $1,454,000 annually for all PBR and standard permits reviewed by the commission based on the last two years of actions.

PUBLIC BENEFITS AND COSTS

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

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

*Increase in Permitting Costs*

Modified or new oil and gas transportation and production sites will incur permitting and operational costs to obtain a new PBR or non-rule standard permit. Staff estimates that approximately 6,000 new and changing OGS will be required to submit a Level 1 post-construction registration ($50-$200) each year, and 3,000 new and changing OGS will be required to submit a Level 2 preconstruction registration ($100-450) each year. In the past many of these OGS would not have required registration. In addition, staff estimates that 500 OGS currently operating under PBR will have to obtain a non-rule standard permit ($900). The estimated annual increase in revenue could be between $1,050,000 and $3,000,000 each year statewide.

*Increase in Operating Costs*

If currently authorized sites are modified or if new facilities are constructed, various operational costs could be incurred.

Sites with fugitive components with an uncontrolled potential to emit of 10 tpy VOC 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. 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; the configuration of the site; on a voluntary basis to reduce estimated emissions; or as a requirement for larger sites with numerous fugitive components and 10 tpy VOC.

To obtain accurate emission estimates, the new PBR would require the sampling of gas streams with a cost of $800 to $1,200 per sample. Sites may require 1 to 6 samples on a one-time basis, depending on the facilities installed. This gives a potential cost range of $800 to $7,200.

The new PBR 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 proposed PBR does not specifically require controls or changes to facilities. However, regulated entities may choose to add controls, or increased destruction effectiveness of controls, to meet the emission limits of the proposed PBR. The following information provides a range of costs for individual equipment and operations options under this proposed rule. A site will incur these costs based on the equipment and operations at a specific site. Additionally, owners of OGS have options for specific types of equipment to perform the same function. For example, generally only one type of thermal destruction device will be used, either a flare or a thermal oxidizer, or the owner/operator may choose to use a vapor recovery unit. The commission does not expect each site to incur all of these costs.

The new PBR would require testing for emissions of total VOCs from engines. This would be expected to increase the total cost of testing for engines and turbines from about $500-$2,000 per test in addition to already required testing under §106.512 or NSPS. The new PBR would also require quarterly monitoring of engines to establish on-going performance. The equipment and resources to complete the photo ionization detector (PID) test) is expected to cost $1,000 per test or $4,000 annually. This will not be a new cost for engines in the Houston/Galveston or Dallas/Fort Worth nonattainment areas as quarterly monitoring has been an applicable requirement in Chapter 117 since 2007.

If a permit holder desires to claim high destruction effectiveness from a thermal oxidizer, condenser, flare, vapor combustor, or vapor recovery unit, the new PBR would require testing to demonstrate the higher effectiveness for emissions. These costs could widely vary between $1,000 to $20,000 dollars depending on the pollutants and type of testing needed.

The new PBR 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 PBR may result in storage tanks being 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.

The new PBR 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.

## SMALL BUSINESS AND MICRO-BUSINESS ASSESSMENT

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

## SMALL BUSINESS REGULATORY FLEXIBILITY ANALYSIS

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

## LOCAL EMPLOYMENT IMPACT STATEMENT

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

DRAFT REGULATORY IMPACT ANALYSIS DETERMINATION

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

Furthermore, while the proposed rulemaking does not constitute a major environmental rule, even if it did, a regulatory impact analysis would not be required because the proposed rulemaking does not meet any of the four applicability criteria for requiring a regulatory impact analysis for a major environmental rule. THSC, §2001.0225 applies only to a major environmental rule which: 1) exceeds a standard set by federal law, unless the rule is specifically required by state law; 2) exceeds an express requirement of state law, unless the rule is specifically required by federal law; 3) exceeds a requirement of a delegation agreement or contract between the state and an agency or representative of the federal government to implement a state and federal program; or 4) adopts a rule solely under the general powers of the agency instead of under a specific state law. The proposed rulemaking does not meet any of the four applicability criteria listed in Texas Government Code, §2001.0225 because: 1) the proposed rulemaking is designed to meet, not exceed the relevant standard set by federal law; 2) parts of the proposed rulemaking are directly required by state law; 3) no contract or delegation agreement covers the topic that is the subject of this rulemaking; and 4) the proposed rulemaking is authorized by specific sections of THSC, Chapter 382 (also known as the TCAA), which is cited in the STATUTORY AUTHORITY section.

The specific intent of the proposed rulemaking is to repeal the current requirements of §106.352 and implement a new set of requirements for the PBR. The new PBR requirements will provide an updated, comprehensive, and protective authorization for many common oil and gas facilities in Texas. The proposed PBR will include operating specifications and emissions limitations for typical equipment (facilities) during normal operation, which includes production and planned MSS. Also, consideration of current emission quantification methods, capture and recovery devices and control equipment will be part of the revised authorizations. The proposed PBR will specifically address the appropriateness of multiple authorizations at one site and would reference the many new federal standards which have been promulgated by the EPA, as well as include revised criteria for registration and changes at existing, authorized sites.

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

TAKINGS IMPACT ASSESSMENT

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

CONSISTENCY WITH THE COASTAL MANAGEMENT PROGRAM

The commission reviewed the proposed rulemaking and found the proposal is a rulemaking identified in the Coastal Coordination Act Implementation Rules, 31 TAC §505.11(b)(2), relating to rules subject to the Coastal Management Program, and will, therefore, require that goals and policies of the Texas Coastal Management Program (CMP) be considered during the rulemaking process. The commission reviewed this proposed rulemaking for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council and determined that the proposed amendments are consistent with CMP goals and policies. The CMP goal applicable to this rulemaking action is the goal to protect, preserve, and enhance the diversity, quality, quantity, functions, and values of coastal natural resource areas (31 TAC §501.12(1)). No new sources of air contaminants will be authorized and the revisions will maintain the same level of emissions control as previous rules. The CMP policy applicable to this rulemaking action is the policy that the commission's rules comply with federal regulations in 40 CFR, to protect and enhance air quality in the coastal areas (31 TAC §501.32). This rulemaking action complies with 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans. Therefore, in accordance with 31 TAC §505.22(e), the commission affirms that this rulemaking action is consistent with CMP goals and policies.

EFFECT ON SITES SUBJECT TO THE FEDERAL OPERATING PERMITS PROGRAM

The amended PBR and standard permit in this proposal are applicable requirements under 30 TAC Chapter 122, Federal Operating Permits Program. Upon the effective date of this rulemaking and standard permit issuance, owners or operators subject to the Federal Operating Permit Program that modify any NSR authorized sources at their sites will be subject to the amended requirements of these sections. Currently, an OGS may be authorized by PBR, standard permit, permits, or a combination of these authorizations. This proposed PBR and standard permit are being developed to provide an updated, comprehensive and protective authorization for common OGS in Texas. The proposed PBR and standard permit address the appropriateness of multiple authorizations at one contiguous property. One of the limitations of the proposed PBR and standard permit only allows OGS which do not require federal preconstruction authorization under PSD or NNSR. However, new and existing OGS may be subject to the Title V federal operating permit program and must obtain a SOP or a 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 December 2008), thus the urgency to pursue these changes and minimize additional, unnecessary paperwork. The commission's intent is to allow for time after the PBR and standard permit are adopted and issued for OGS to update or apply for the PBR or standard permit, before the December 2008 GOP revision or SOP application deadlines.

ANNOUNCEMENT OF HEARING

A public hearing has been scheduled September 14, 2010 at 10:00 a.m. in Bldg E, Room 201S for Rule Project Number 2010-018-106-PR. The subjects of this hearing will be the proposed repeal of and new §106.352; the repeal of §116.620, Installation and/or Modification of Oil and Gas Facilities; and the new Air Quality Standard Permit for Oil and Gas Facilities. Staff will be available for questions at 9:30 a.m. at the commission's central office located at 12100 Park 35 Circle. The hearing is structured for the receipt of oral or written comments by interested persons. Individuals may present oral statements when called upon in order of registration. Open discussion will not be permitted during the hearing; however, commission staff members will be available to discuss the proposal 30 minutes prior to the hearing.

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

SUBMITTAL OF COMMENTS

Written comments may be submitted to Michael Parrish, MC 205, Office of Legal Services, Texas Commission on Environmental Quality, P.O. Box 13087, Austin, Texas 78711-3087, or faxed to (512) 239-4808. Electronic comments may be submitted at: *http://www5.tceq.state.tx.us/rules/ecomments/*. File size restrictions may apply to comments being submitted via the eComments system. All comments should reference Rule Project Number 2010-018-106-PR. The comment period closes September 17, 2010. Copies of the proposed rulemaking can be obtained from the commission's Web site at *http://www.tceq.state.tx.us/nav/rules/propose_adopt.html*. For further information, please contact Anne Inman at 512-239-1276 or by e-mail at *ainman@tceq.state.tx.us*.

**SUBCHAPTER O: OIL AND GAS**

**[§106.352]**

STATUTORY AUTHORITY

The repeal of this section is proposed under Texas Water Code, §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the Texas Water Code; and under Texas Health and Safety Code, §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purposes of the Texas Clean Air Act. The repeal is also proposed under Texas Health and Safety Code, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.051, concerning Permitting Authority of Commission; Rules, which authorizes the commission to issue a permit by rule for types of facilities that will not significantly contribute air contaminants to the atmosphere; §382.05196, concerning Permits by Rule, which authorizes the commission to adopt permits by rule for certain types of facilities; and §382.057, concerning Exemption, which authorizes exemptions from permitting.

The proposed repeal implements Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.017, 382.051, 382.05196, and 382.057.

[**§106.352. Oil and Gas Production Facilities.**]

[Any oil or gas production facility, carbon dioxide separation facility, or oil or gas pipeline facility consisting of one or more tanks, separators, dehydration units, free water knockouts, gunbarrels, heater treaters, natural gas liquids recovery units, or gas sweetening and other gas conditioning facilities, including sulfur recovery units at facilities conditioning produced gas containing less than two long tons per day of sulfur compounds as sulfur are permitted by rule, provided that the following conditions of this section are met. This section applies only to those facilities named which handle gases and liquids associated with the production, conditioning, processing, and pipeline transfer of fluids found in geologic formations beneath the earth's surface.]

[(1) Compressors and flares shall meet the requirements of §106.512 and §106.492 of this title (relating to Stationary Engines and Turbines, and Flares).]

[(2) Total emissions, including process fugitives, combustion unit stacks, separator, or other process vents, tank vents, and loading emissions from all such facilities constructed at a site under this section shall not exceed 25 tons per year (tpy) each of sulfur dioxide ($SO_2$), all other sulfur compounds combined, or all volatile organic compounds (VOC) combined; and 250 tpy each of nitrogen oxide and carbon monoxide. Emissions of VOC and sulfur compounds other than $SO_2$ must include gas lost by equilibrium flash as well as gas lost by conventional evaporation.]

[(3) Any facility handling sour gas shall be located at least 1/4 mile from any recreational area or residence or other structure not occupied or used solely by the owner or operator of the facility or the owner of the property upon which the facility is located.]

[(4) Total emissions of sulfur compounds, excluding sulfur oxides, from all vents shall not exceed 4.0 pounds per hour (lb/hr) and the height of each vent emitting sulfur compounds shall meet the following requirements, except in no case shall the height be less than 20 feet:]

[Figure: 30 TAC 106.352(4)]

| Total as<br>Hydrogen Sulfide, lb/hr | Minimum<br>vent height, feet |
|---|---|
| 0.27 | 20 |
| 0.60 | 30 |
| 1.94 | 50 |
| 3.00 | 60 |
| 4.00 | 68 |

[NOTE: Other values may be interpolated.]

[(5) Before operation begins, facilities handling sour gas shall be registered with the commission's Office of Permitting, Remediation, and Registration in Austin using Form PI-7 along with supporting documentation that all requirements of this section will be met. For facilities constructed under

§106.353 of this title (relating to Temporary Oil and Gas Facilities), the registration is required before operation under this section can begin. If the facilities cannot meet this section, a permit under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) is required prior to continuing operation of the facilities.]

**SUBCHAPTER O: OIL AND GAS**

**§106.352**

STATUTORY AUTHORITY

The new section is proposed under Texas Water Code, §5.103, concerning Rules, and §5.105, concerning General Policy, which authorize the commission to adopt rules necessary to carry out its powers and duties under the Texas Water Code; and under Texas Health and Safety Code, §382.017, concerning Rules, which authorizes the commission to adopt rules consistent with the policy and purposes of the Texas Clean Air Act. The new section is also proposed under Texas Health and Safety Code, §382.002, concerning Policy and Purpose, which establishes the commission's purpose to safeguard the state's air resources, consistent with the protection of public health, general welfare, and physical property; §382.011, concerning General Powers and Duties, which authorizes the commission to control the quality of the state's air; §382.012, concerning State Air Control Plan, which authorizes the commission to prepare and develop a general, comprehensive plan for the control of the state's air; §382.051, concerning Permitting Authority of Commission; Rules, which authorizes the commission to issue a permit by rule for types of facilities that will not significantly contribute air contaminants to the atmosphere; §382.05196, concerning Permits by Rule, which authorizes the commission to adopt permits by rule for certain types of facilities; and §382.057, concerning Exemption, which authorizes exemptions from permitting.

The proposed new section implements Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.017, 382.051, 382.05196, and 382.057.

**§106.352. Oil and Gas Site.**

(a) Applicability. This section 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 permit by rule (PBR) for an oil and gas site (OGS) may be claimed or registered for each site and authorizes all facilities in sweet or sour service. This section may not be used if operationally related facilities are authorized by the Air Quality Standard Permit for Oil and Gas Sites, or a permit under §116.111 of this title (relating to General Application). Except for planned maintenance, startup, and shutdown (MSS) activities which must meet the requirements of subsection (i) of this section, any site with a permit under §116.111 of this title cannot also claim this section for any new facility, or changes to an existing facility, which handles (or is related to the processing of) crude oil, condensate, natural gas, or any other petroleum raw material, product, or by-product. Other facilities which are not covered under this section may be authorized by other PBRs at an OGS if subsection (b)(6) of this section is met;

(2) This section 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 section are not authorized and are violations of the PBR.

(3) Emissions from upsets, emergencies, or malfunctions are not authorized by this section. This section 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, drilling, or a 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 section 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 OGS facility, or the mineral rights owner of the property upon which the OGS facility is located. All measurements of distance to receptors shall be taken from the emission release point at the OGS facility that is nearest to the point on the building that is nearest to the OGS facility.

(3) 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 two digit standard industrial classification (SIC) codes.

(4) For purposes of determining applicability of Chapter 122 of this title (relating to Federal Operating Permits), the definitions of §122.10 of this title (relating to General Definitions), apply.

(5) For purposes of claim or registration under this section, the following must be met.

(A) Any new facility or new group of operationally 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 certified, must meet all requirements of this section prior to construction or implementation of changes.

(B) Existing authorized facilities, or group of facilities, at an OGS under this section which are not changing certified character or quantity of emissions must only meet paragraph (6) of this subsection and subsection (i) of this section.

(C) A single PBR 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 section. 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 section must collectively emit less than or equal to 250 tons per year (tpy) of nitrogen oxides ($NO_X$) or carbon monoxide (CO) and 25 tpy of volatile organic compounds (VOC), sulfur dioxide ($SO_2$), particulate matter with less than 10 microns ($PM_{10}$), hydrogen sulfide ($H_2S$), or any other air contaminant.

(E) Planned MSS information is not required to be registered if no other changes are occurring. If the existing OGS is certified, an addendum to the OGS certification may be filed using Form APD-CERT by hard-copy or the E-permits system. No fee is required for this updated certification. For facilities authorized under §116.111 of this title, only records of MSS as specified in this section must be kept. Planned MSS information sufficient to demonstrate compliance with this section shall be incorporated at the next revision or update to a registration under this section after January 5, 2012.

(6) 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 1/4 mile of a project requiring registration under this section shall be evaluated, including fugitive components. If a claim under this section is only for planned MSS under subsection (i) of this section, the analysis shall evaluate planned MSS only.

(B) Hourly and annual emissions shall be limited based on the most stringent of subsections (g), (h), or (k) of this section. Compliance with ambient air standards shall be demonstrated for any property-line within 2,700 feet of a project under this section for the following air contaminants:

$NO_X$, $SO_2$, and $H_2S$ unless otherwise listed in subsection (k) of this section. 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 section unless otherwise listed in subsection (k) of this section.

(7) For purposes of all previous claims of this section (or any previous version of this section):

(A) existing authorized facilities, or group of facilities, at an OGS must meet only subsection (i) of this section; and

(B) identifying information (updated Core Data and basic identifying information) must be submitted through E-permits (or if not available, hard-copy) using the "Air Permits Division OGS Basic Notification" and must be provided no later than January 1, 2013. No fee is required for this notification.

(c) Authorized Facilities, Changes, and Activities.

(1) For existing OGS which are authorized by previous versions of this section.

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

(B) Addition of any piping, fugitive components, any other new facilities, or changes to any existing facilities that increase the OGS potential to emit or certified emissions less than or equal to 1.0 tpy VOC, five tpy $NO_X$, 0.01 tpy benzene, and 0.05 tpy $H_2S$, or addition of any new engine rated less than 100 horsepower (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 less than or equal to five tpy VOC or $NO_X$, 0.05 tpy benzene, or 0.1 tpy $H_2S$, or a registration or registration update under this section 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 previously certified representations;

(iii) the fugitive components or other new facilities must meet the applicable requirements of subsections (e) and (j) of this section; and

(iv) these facilities and changes shall be incorporated at the next revision or update to a registration or certification under this section.

(C) Replacement of any facility is authorized, does not require registration, and must meet only the applicable requirements of subsection (e) of this section if:

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

(ii) replacement facility information shall be incorporated at the next revision or update to a registration or certification under this section.

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

(A) new, changed, or replacement facilities shall not exceed the thresholds for major source or major modification as defined in §116.12 of this title (relating to 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 40 Code of Federal Regulations (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, of this title (relating to Control of Air Pollution from Visible Emissions and Particulate Matter), 112 of this title (relating to Control of Air Pollution from Sulfur Compounds), 113 of this title (relating to Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants), 115 of this title (relating to Control of Air Pollution from Volatile Organic Compounds), and 117 of this title (relating to Control of Air Pollution from Nitrogen Compounds).

(3) The executive director may deny an application for registration under this section for good cause.

(d) Facilities and Exclusions.

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

(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(R), 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 section:

(A) sour water strippers or sulfur recovery units;

(B) carbon dioxide hot carbonate processing units;

(C) water injection facilities. These facilities may otherwise authorized by §106.351 of this title (relating to Salt Water Disposal (Petroleum));

(D) liquefied petroleum gases, crude oil, or condensate transfer or loading into or from railcars, ships, or barges. These facilities may otherwise authorized by §106.261 of this title (relating to Facilities (Emission Limitations)) and §106.262 of this title (relating to Facilities (Emissions and Distance Limitations));

(E) incinerators for solid waste destruction;

(F) remediation of petroleum contaminated water and soil. These facilities may otherwise authorized by §106.533 of this title (relating to Remediation);

(G) cooling towers and heat exchangers with direct contact with gaseous or liquid process streams containing VOC, $H_2S$, 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 previously certified representations, and any associated emission control equipment at an OGS registered under this section, 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 section, 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 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 section is claimed, registered, or certified (provided that the authorization was maintained) regardless of whether a receptor is subsequently built or put to use 50 feet from any OGS facility; or

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

(4) Engines and turbines shall meet the following:

(A) the emission and performance standards listed in Table 9 in subsection (l) of this section;

(B) documentation of the engine's manufacture 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 needs 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 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 subsection (1), Table 9 of this section 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 Chapter 117 of this title; and

(F) all applicable requirements of 40 CFR Part 60 and 40 CFR Part 63.

(5) Open-topped tanks or ponds containing VOCs or $H_2S$ are allowed up to a PTE equal to 1 tpy of VOC and 0.1 tpy of $H_2S$.

(6) The following shall apply to fugitives:

(A) each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve to seal the line so that no leakage of emissions occurs unless otherwise required to maintain safe operations in a vessel or pipeline;

B) all seals and gaskets in VOC or $H_2S$ service shall be installed, checked, and properly maintained to prevent leaking; and

(C) tank hatches, not designed to be completely sealed, shall remain closed (but not completely sealed in order to maintain safe design functionality) except for sampling or planned maintenance activities.

(7) New and replaced fugitive components and instrumentation in gas or liquid service at the site with the uncontrolled potential to emit equal to or greater than 10 tpy VOC or one tpy $H_2S$ shall comply with the following fugitive monitoring program. This paragraph applies to fugitive components which are not otherwise subject to 40 CFR Part 60, Subpart KKK (relating to Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants), NSPS, or voluntarily implementing a leak detection and repair (LDAR) program.

(A) Corresponding to the frequency established in 49 CFR §192.706 (relating to Transmission Lines: Leakage Surveys) all fugitive components shall be all inspected by audio, visual, and olfactory (AVO) observation, at intervals not exceeding 15 months, but at least once each calendar year.

(B) The inspections specified in subparagraph (A) of this paragraph must also include monitoring for leaking components using the United States Environmental Protection Agency (EPA) Test Method 21, with a portable analyzer set at 10,000 parts per million by volume (ppmv), leak detection limit. In lieu of the portable analyzer, the owner or operator may use the alternative work practice in 40 CFR §60.18(g) - (i) (relating to General Control Device and Work Practice Requirements) to perform inspections with the following provisions:

(i) the monitoring frequency using an optical gas imaging instrument and the alternative work practice must be at least annually;

(ii) the optical gas imaging instrument must have a detection sensitivity level of no greater than 60 grams per hour; and

(iii) the annual Test Method 21 requirement in 40 CFR §60.18(h)(7) and the reporting requirement in 40 CFR §60.18(i)(5) do not apply.

(C) Damaged or leaking valves, connectors, pumps, compressors, and agitator seals found to be emitting VOCs in excess of 10,000 ppmv as determined using a portable analyzer, found by AVO inspection to be leaking (e.g., dripping process fluids), or found leaking using the alternative work practice shall be tagged and replaced or repaired.

(D) Every reasonable effort shall be made to repair a leaking component. At manned sites, leaks shall be repaired within 30 days after the leak is found. At unmanned sites, leaks shall be repaired within 60 days after the leak is found. If the repair of a component would require a unit shutdown, which would create more emissions than the repair would eliminate, the repair may be delayed until the next planned shutdown.

(E) To the extent that good engineering practices will permit, new and reworked valves and piping connections shall be located in a place that is reasonably accessible for leak checking during plant operation.

(f) Additional 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 previously certified representations, and any associated emission control equipment at an OGS registered under this section, the following specifications, design, and control requirements are applicable. Equipment design and control device requirements only apply to those that are needed to meet the emission limitations of this section and must document compliance in accordance with subsection (j) of this section.

(1) Tanks and vessels 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 Compilation of Air Pollutant Emission Factors (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 vapor recovery unit (VRU) may be used to control emissions. Exceptions to the color requirement include:

(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 aethestic purposes; and

(B) if a local, state or federal law or ordinance or private contract which predates this section'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.

(2) Glycol dehydrator unit condensers may claim the design efficiency up to 80% control where the condensate receiver vessel is enclosed and appropriate monitoring is applied. Greater efficiencies may be claimed where enhanced monitoring and testing are applied.

(3) Process reboilers, heaters, and furnaces that are also 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 in subsection (j) of this section. Any value greater than 90% and up to 99% destruction efficiency may be claimed where enhanced monitoring and/or testing are applied as specified in subsection (j) of this section. 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 in subsection (j) of this section. 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.

(4) Vapor recovery units may claim up to 80% control for units where appropriate design

requirements and conditions are practiced and appropriate monitoring, as listed in subsection (1), Table 8 of this section for vapor capture and recovery, is applied. 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.

(5) Flares used for control of emissions from production, planned MSS, emergency, or upset uses may claim design destruction efficiency of 98% and must be designed and operated in accordance with the following:

(A) meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;

(B) if necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible;

(C) an infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes;

(D) an automatic ignition system may be used in lieu of a continuous pilot;

(E) flares must be lit at all times when gas streams are present;

(F) fuel for all flares shall be sweet gas or liquid petroleum gas; and

(G) 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 §111.111(a)(4) of this title (relating to Requirements for Specified Sources), regarding gas flares, are exempt from this visible emission limitation.

(6) Thermal oxidation and vapor combustion control devices may claim design destruction efficiency from 90 to 99.9% depending on the design and the level of monitoring and testing applied. A device designed for the variability of the waste gas streams it controls with basic monitoring to indicate oxidation or combustion is occurring when waste gas is directed to the device may claim 90% destruction efficiency. 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 1,400 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 90 to 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 1,400 degrees F for 0.5 seconds, residence time. The devices that can claim 99% destruction efficiency 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.

(g) Level 1 post-construction registration. Total maximum estimated emissions shall meet the most stringent of the following.

(1) Emissions of any criteria air contaminant shall not exceed the applicable limits for a major stationary source or major modification for prevention of significant deterioration (PSD), nonattainment new source review (NNSR) as specified in §116.12 of this title and in Federal Clean Air Act §112(g), §112(j), or the definition of major source in §122.10 of this title (relating to General Definitions).

(2) If an OGS meets the following, the facilities must be registered within 180 days after well completion, start of operation, or implemented changes, whichever occurs first. The OGS must consist of only fugitive components, separators, engines, and tanks and any associated control devices and have the potential of less than the following emissions after any recovery or controls:

(A) Total VOCs are limited to 25 pounds per hour (lb/hr) and 5 tpy and:

(i) 0.8 lb/hr and 1.2 tpy benzene;

(ii) 3.1 lb/hr toluene;

(iii) 1.7 lb/hr xylene; and

(iv) 0.9 lb/hr formaldehyde;

(B) Sulfur compounds are limited to the following:

(i) 0.5 lb/hr and 2.2 tpy $H_2S$; and

(ii) 5.4 lb/hr and 10 tpy $SO_2$;

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

(i) 9 lb/hr and 25 tpy $NO_X$;

(ii) 11.4 lb/hr and 50 tpy CO; and

(iii) 0.50 tpy $PM_{10}$/$PM_{2.5}$.

(3) If an OGS meets the following, the facilities must be registered within 90 days after well completion, start of operation, or implemented changes, whichever occurs first. The OGS must have the potential of less than the following emissions after any recovery or controls:

(A) Total VOCs are limited to 50 lb/hr and 10 tpy, plus the following:

(i) 1.8 lb/hr and 2.5 tpy benzene;

(ii) 6 lb/hr toluene;

(iii) 3 lb/hr xylene; and

(iv) 1.5 lb/hr formaldehyde.

(B) Sulfur compounds are limited to the following:

(i) 2 lb/hr and 4.5 tpy $H_2S$; and

(ii) 8 lb/hr and 15 tpy $SO_2$.

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

(i) 25 lb/hr and 100 tpy $NO_X$;

(ii) 22.8 lb/hr and 100 tpy CO; and

(iii) 1 tpy $PM_{10}$/$PM_{2.5}$.

(4) OGS owner or operator shall submit registrations to the executive director in accordance with the following.

(A) Registrations must be submitted through E-permits or hard-copy of form "Air Permits Division OGS PBR Level 1 Registration."

(B) 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 for determining emissions.

(C) Registrations shall remit one of the following fees:

(i) E-permits submittals shall be accompanied by a $50 fee for small business, non-profit organization, or small governmental entities or $200 for all other entities; or

(ii) hard-copy submittals shall be accompanied by the fee established in §106.50 of this title (relating to Registration Fees for Permits by Rule).

(h) Level 2 Preconstruction Registration. If the requirements of the Level 1 Notification cannot be met, then the conditions of this subsection must be followed.

(1) Total maximum estimated annual emissions of any air contaminant shall not exceed the applicable limits for a major stationary source or major modification for PSD and NNSR as specified in §116.12 of this title.

(2) If an OGS meets the following, the facilities must be must be registered and approved prior to start of construction or implemented changes, whichever occurs first. After any recovery or controls, the OGS must have the potential of less than:

(A) Total VOCs are limited to 75 lb/hr and 25 tpy, plus the following:

(i) 2.25 lb/hr and 3.5 tpy benzene;

(ii) 7 lb/hr toluene;

(iii) 4 lb/hr xylene; and

(iv) 2 lb/hr formaldehyde.

(B) Sulfur compounds are limited to the following:

(i) 6 lb/hr and 9 tpy $H_2S$; and

(ii) 12 lb/hr and 25 tpy $SO_2$.

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

(i) 50 lb/hr and 250 tpy $NO_X$;

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

(iii) 2 tpy $PM_{10}$/$PM_{2.5}$.

(3) Certifications to establish enforceable emission limits shall be submitted in the following circumstances.

(A) For projects at existing major sites, establish emission increases less than any applicable threshold or contemporaneous emission increases for major sources or major modifications under NNSR or PSD.

(B) If a project includes control technology, limited hours, throughput, and materials or other operational limitations which are less than the PTE.

(C) If a project is located at a site subject to $NO_X$ cap and trade requirements in Chapter 101, Subchapter H of this title (relating to Emissions Banking and Trading).

(D) For projects which resolve compliance issues and are the result of a commission or EPA order.

(E) For claims under this section following paragraph (i)(4) of this section relating to planned MSS.

(4) The owner or operator of the OGS shall submit a registration in accordance with the following.

(A) Use Form PI-7 Registration for Permits by Rule, or if appropriate, a certified registration using Form PI-7-CERT Certification and Registration for Permits by Rule.

(B) Construction shall not begin nor changes implemented until written confirmation is issued by the commission.

(C) 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.

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

(E) Pre-construction registrations shall remit the fee established in §106.50 of this title.

(i) Planned Maintenance, Startups and Shutdowns. For any facility, group of facilities or site using this section or previous versions of this section, 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 section. After January 5, 2012, all emissions from planned MSS activities and facilities must be considered for compliance with applicable limits of this section. This section may not be used at a site or for facilities authorized under §116.111 of this title 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 section, 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) 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;

(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); and

(G) hot oil treatments.

(3) Other planned MSS activities authorized by this section 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.

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

(4) Engine/compressor 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 and certified 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 $H_2S$.

(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 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) of this section.

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

(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 commissioner's internet webpage.

(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 $NO_X$ to $NO_2$ 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 areless than the following rates, no additional analysis or demonstration of the specified air contaminant is required:

(i) 9 lb/hr $NO_X$;

(ii) 0.025 lb/hr $H_2S$;

(iii) 0.42 lb/hr $SO_2$;

(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 section where:

(i) Emission impact tables may be used in accordance with the limits and descriptions in Table 1 in subsection (1) of this section.

(ii) Values in Tables 2 - 6 in subsection (l) of this section 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 subsection (f)(1) of this section 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 section 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 section if all of the parameters in the refined dispersion modeling protocol provided by the commission are met.

(l) The following tables shall be used as required in subsection (k) of this section.

Figure: 30 TAC §106.352(l)

**Table 1 Emission Impact Tables Limits and Descriptions**

| **Topic** | **Description** | **Details** |
|---|---|---|
| Variables | $E_{MAX\ HOURLY}$ | the maximum acceptable hourly (lb/hr) emissions |
| | $E_{MAX\ ANNUAL}$ | the maximum acceptable annual (tpy) emissions |
| | P | ambient air standard ($\mu g/m^3$) |
| | ESL | current published effects screening level for the specific air contaminant ($\mu g/m^3$) |
| | G | the most stringent of any applicable generic value from the Tables at the emission point's release height and distance to property line ($\mu g/m^3/lb/hr$) |
| | WR EPN(x)= | Weighted ratio of emissions for each EPN divided by the sum of total Emissions for all EPNs that emit that contaminant or ($E_{EPN\ x}/E_{total}$) |
| single releases or co-located groups of similar releases | hourly ambient air standard | emissions are determined by: ***$E_{MAX\ HOURLY}$ = P/G*** |
| | hourly health effects review | emissions are determined by: ***$E_{MAX}$ = ESL/G*** |
| | annual ambient air standard | emissions are determined by: ***$E_{MAX\ ANNUAL}$ = (8760/2000) P/(0.08*G)*** |
| | annual health effects review | emissions are determined by: ***$E_{MAX\ ANNUAL}$ = (8760/2000) ESL/(0.08*G)*** |
| Multiple Release Points | Limits | If weighted ratios are not used, the total quantity of emissions shall be assumed to be released from the most conservative applicable G value at the site. |
| | hourly ambient air standard | emissions are determined by: ***$E_{MAX\ HOURLY}$ = (WR EPN1) (P / G EPN1) + (WR EPN2) (P / G EPN2) + …(WR EPN(x)) (P / G EPN(x))*** |
| | hourly health effects review | emissions are determined by: ***$E_{MAX\ HOURLY}$ = (WR EPN1) (ESL /G EP 1) + (WR EPN2) (ESL/G EPN2) + …..(WR EPN(x)) (ESL / G EPN(x))*** |
| | annual ambient air standard | emissions are determined by ***$E_{MAX\ ANNUAL}$ = (8760/2000) ( (WR EPN1) (P / 0.08*G EPN1) + (WR EPN2) (P / 0.08*G EP 2) + .... (WR EPN(x) ) (P / [0.08*G EPN(x) ) )*** |
| | annual health effects review | emissions are determined by ***$E_{MAX\ ANNUAL}$ = (8760/2000) ( (WR EPN1) (ESL /[0.08*G EPN1]) + (WR EPN2) (ESL/0.08*G EPN2) + …(WR EPN(x) ) (ESL / 0.08*G EPN(x) ) )*** |

**Table 2. Generic Modeling Results for Fugitives & Process Vents**

| Distance | Fugitive - 3ft | Loading -10 ft | Tank Hatch - 20 ft | Process Vessel 10 ft Vent | Process Vessel 20 ft Vent | Process Vessel 30 ft Vent | Process Vessel 40 ft Vent | Process Vessel 50 ft Vent | Process Vessel 60 ft Vent |
|---|---|---|---|---|---|---|---|---|---|
| (feet) | (µg/m³)/(lb/hr) | (µg/m³)/(lb/hr) | (µg/m³)/(lb/hr) | (µg/m³)/(lb/hr) | (µg/m³)/(lb/hr) | (µg/m³)/(lb/hr) | (µg/m³)/(lb/hr) | (µg/m³)/(lb/hr) | (µg/m³)/(lb/hr) |
| 50 | 4375 | 1232 | 305 | 469 | 168 | 90 | 70 | 65 | 28 |
| 100 | 4375 | 1232 | 305 | 469 | 168 | 90 | 70 | 65 | 28 |
| 150 | 3907 | 1232 | 305 | 469 | 168 | 90 | 70 | 65 | 28 |
| 200 | 3089 | 1232 | 305 | 440 | 168 | 90 | 70 | 65 | 28 |
| 300 | 1911 | 1193 | 294 | 412 | 168 | 90 | 70 | 65 | 28 |
| 400 | 1269 | 1048 | 291 | 319 | 168 | 90 | 70 | 65 | 28 |
| 500 | 901 | 858 | 274 | 243 | 157 | 90 | 70 | 65 | 28 |
| 600 | 674 | 698 | 267 | 189 | 138 | 89 | 70 | 65 | 28 |
| 700 | 525 | 574 | 271 | 150 | 120 | 88 | 70 | 65 | 28 |
| 800 | 423 | 479 | 261 | 124 | 105 | 85 | 70 | 65 | 28 |
| 900 | 349 | 406 | 244 | 105 | 93 | 81 | 70 | 65 | 28 |
| 1000 | 293 | 348 | 226 | 91 | 84 | 77 | 69 | 65 | 26 |
| 1100 | 250 | 302 | 208 | 90 | 77 | 72 | 67 | 63 | 25 |
| 1200 | 217 | 264 | 191 | 89 | 70 | 68 | 64 | 61 | 24 |
| 1300 | 189 | 233 | 176 | 88 | 65 | 64 | 61 | 58 | 24 |
| 1400 | 167 | 208 | 161 | 87 | 61 | 60 | 58 | 55 | 24 |
| 1500 | 149 | 186 | 149 | 84 | 57 | 57 | 55 | 53 | 24 |
| 1600 | 134 | 168 | 137 | 82 | 54 | 53 | 52 | 50 | 23 |
| 1700 | 121 | 153 | 127 | 79 | 51 | 51 | 49 | 47 | 23 |
| 1800 | 110 | 139 | 117 | 76 | 50 | 48 | 47 | 45 | 22 |
| 1900 | 100 | 128 | 109 | 73 | 49 | 46 | 44 | 43 | 22 |
| 2000 | 92 | 117 | 102 | 70 | 49 | 44 | 42 | 41 | 21 |
| 2100 | 85 | 108 | 95 | 67 | 48 | 42 | 41 | 39 | 21 |
| 2200 | 78 | 101 | 89 | 64 | 47 | 40 | 39 | 38 | 20 |
| 2300 | 73 | 94 | 83 | 61 | 46 | 39 | 37 | 36 | 19 |
| 2400 | 68 | 88 | 78 | 59 | 45 | 37 | 36 | 35 | 19 |
| 2500 | 64 | 82 | 74 | 56 | 43 | 36 | 35 | 34 | 18 |
| 2600 | 60 | 77 | 70 | 54 | 42 | 34 | 33 | 32 | 18 |
| 2700 | 56 | 73 | 66 | 52 | 41 | 33 | 32 | 31 | 17 |

**Table 3. Generic Modeling Results for Engines and Turbines for Engines and Turbines Less than or Equal to 1000 horsepower**

| Distance | 8 ft | 10 ft | 12 ft | 14 ft | 16ft | 18ft | 20 ft | 25 ft | 30 ft | 35 ft | 40 ft |
|---|---|---|---|---|---|---|---|---|---|---|---|
| (ft) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) | (µg/m³) /(lb/hr) |
| 50 | 27 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 100 | 27 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 150 | 27 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 200 | 27 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 300 | 26 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 400 | 26 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 500 | 26 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 600 | 26 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 700 | 26 | 25 | 25 | 25 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 800 | 24 | 24 | 24 | 24 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 900 | 23 | 23 | 23 | 23 | 18 | 18 | 17 | 13 | 13 | 11 | 10 |
| 1000 | 21 | 21 | 21 | 21 | 17 | 17 | 17 | 13 | 13 | 11 | 10 |
| 1100 | 20 | 20 | 20 | 20 | 17 | 17 | 16 | 13 | 13 | 11 | 10 |
| 1200 | 18 | 18 | 18 | 18 | 17 | 16 | 16 | 12 | 12 | 11 | 10 |
| 1300 | 17 | 17 | 17 | 17 | 17 | 15 | 15 | 12 | 12 | 10 | 10 |
| 1400 | 17 | 17 | 17 | 17 | 17 | 14 | 14 | 11 | 11 | 10 | 10 |
| 1500 | 17 | 17 | 17 | 16 | 16 | 13 | 13 | 11 | 11 | 10 | 9 |
| 1600 | 17 | 17 | 17 | 16 | 16 | 13 | 13 | 11 | 11 | 10 | 9 |
| 1700 | 16 | 16 | 16 | 15 | 15 | 13 | 12 | 11 | 11 | 10 | 9 |
| 1800 | 16 | 16 | 16 | 15 | 15 | 13 | 12 | 11 | 11 | 10 | 9 |
| 1900 | 15 | 15 | 15 | 14 | 14 | 13 | 12 | 11 | 11 | 10 | 9 |
| 2000 | 15 | 15 | 15 | 14 | 14 | 13 | 12 | 11 | 11 | 10 | 9 |
| 2100 | 14 | 14 | 14 | 13 | 13 | 12 | 12 | 11 | 11 | 10 | 9 |
| 2200 | 14 | 14 | 14 | 13 | 13 | 12 | 12 | 11 | 10 | 9 | 9 |
| 2300 | 13 | 13 | 13 | 12 | 12 | 12 | 11 | 11 | 10 | 9 | 8 |
| 2400 | 13 | 13 | 13 | 12 | 12 | 12 | 11 | 11 | 10 | 9 | 8 |
| 2500 | 12 | 12 | 12 | 12 | 12 | 11 | 11 | 10 | 10 | 9 | 8 |
| 2600 | 12 | 12 | 12 | 11 | 11 | 11 | 11 | 10 | 10 | 9 | 8 |
| 2700 | 12 | 12 | 12 | 11 | 11 | 11 | 10 | 10 | 9 | 9 | 8 |

**Table 4: For Engines and Turbines Greater Than or Equal to 1000 hp**

| Distance (ft) | 8 ft (µg/m³) /(lb/hr) | 10 ft (µg/m³) /(lb/hr) | 12 ft (µg/m³) /(lb/hr) | 14 ft (µg/m³) /(lb/hr) | 16ft (µg/m³) /(lb/hr) | 18ft (µg/m³) /(lb/hr) | 20 ft (µg/m³) /(lb/hr) | 25 ft (µg/m³) /(lb/hr) | 30 ft (µg/m³) /(lb/hr) | 35 ft (µg/m³) /(lb/hr) | 40 ft (µg/m³) /(lb/hr) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 50 | 13 | 12 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 100 | 13 | 12 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 150 | 13 | 12 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 200 | 13 | 12 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 300 | 13 | 12 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 400 | 13 | 11 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 500 | 12 | 11 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 600 | 11 | 11 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 700 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 800 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 900 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 1000 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 8 | 7 | 7 | 6 |
| 1100 | 10 | 10 | 9 | 9 | 9 | 9 | 8 | 8 | 7 | 7 | 6 |
| 1200 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 7 | 7 | 6 |
| 1300 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 7 | 6 | 6 |
| 1400 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 6 | 6 |
| 1500 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 6 | 6 |
| 1600 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 6 | 6 |
| 1700 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 6 | 6 |
| 1800 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 6 | 6 |
| 1900 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 | 7 | 6 | 6 |
| 2000 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 | 6 | 6 | 5 |
| 2100 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 | 6 | 6 | 5 |
| 2200 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 | 6 | 6 | 5 |
| 2300 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 6 | 6 | 6 | 5 |
| 2400 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 5 |
| 2500 | 7 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 5 | 5 |
| 2600 | 7 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 5 | 5 |
| 2700 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 6 | 5 | 5 |

## Table 5. Generic Modeling Results for Flares

| | Concentration per 1 pound/hour of emissions {(µg/m³)/(lb/hr)} | | | | |
|---|---|---|---|---|---|
| Distance (ft) | 20 ft height | 30 ft height | 40 ft height | 50 ft height | 60 ft height |
| 50 | 58 | 43 | 26 | 25 | 23 |
| 100 | 58 | 43 | 26 | 25 | 23 |
| 150 | 58 | 43 | 26 | 25 | 23 |
| 200 | 58 | 43 | 26 | 25 | 23 |
| 300 | 58 | 43 | 26 | 25 | 23 |
| 400 | 58 | 43 | 26 | 25 | 23 |
| 500 | 58 | 43 | 26 | 25 | 23 |
| 600 | 56 | 43 | 26 | 25 | 23 |
| 700 | 52 | 43 | 26 | 25 | 23 |
| 800 | 47 | 43 | 26 | 25 | 23 |
| 900 | 45 | 43 | 26 | 25 | 23 |
| 1000 | 44 | 43 | 26 | 25 | 23 |
| 1100 | 42 | 41 | 25 | 24 | 23 |
| 1200 | 40 | 40 | 24 | 24 | 22 |
| 1300 | 38 | 38 | 23 | 23 | 21 |
| 1400 | 36 | 36 | 23 | 21 | 21 |
| 1500 | 34 | 34 | 23 | 21 | 20 |
| 1600 | 32 | 32 | 22 | 21 | 20 |
| 1700 | 31 | 31 | 22 | 21 | 20 |
| 1800 | 29 | 29 | 22 | 20 | 20 |
| 1900 | 28 | 28 | 22 | 20 | 20 |
| 2000 | 26 | 26 | 21 | 20 | 19 |
| 2100 | 25 | 25 | 21 | 20 | 19 |
| 2200 | 24 | 24 | 20 | 20 | 19 |
| 2300 | 23 | 23 | 20 | 19 | 19 |
| 2400 | 22 | 22 | 20 | 19 | 18 |
| 2500 | 22 | 22 | 19 | 18 | 18 |
| 2600 | 21 | 21 | 19 | 18 | 17 |
| 2700 | 20 | 20 | 18 | 17 | 17 |

**Table 6. Generic Modeling Results for Blowdowns & Gas Pipeline Purging**

| | Blowdowns | | | Purging | | |
|---|---|---|---|---|---|---|
| | concentration per 1 pound/hour of emissions {(µg/m³)/(lb/hr)} | | | | | |
| Distance (feet) | 3 ft height | 10 ft height | 20 ft height | 3 ft height | 10 ft height | 20 ft height |
| 50 | 4304 | 791 | 244 | 2203 | 536 | 191 |
| 100 | 4304 | 791 | 244 | 2203 | 536 | 191 |
| 150 | 4250 | 777 | 244 | 2127 | 536 | 191 |
| 200 | 3621 | 763 | 244 | 2025 | 534 | 191 |
| 300 | 2367 | 750 | 225 | 1692 | 532 | 188 |
| 400 | 1607 | 737 | 225 | 1295 | 516 | 185 |
| 500 | 1156 | 671 | 224 | 993 | 500 | 180 |
| 600 | 871 | 581 | 218 | 777 | 466 | 177 |
| 700 | 682 | 498 | 212 | 624 | 418 | 174 |
| 800 | 551 | 427 | 210 | 513 | 370 | 170 |
| 900 | 456 | 368 | 204 | 429 | 327 | 167 |
| 1000 | 384 | 320 | 194 | 365 | 290 | 164 |
| 1100 | 328 | 281 | 182 | 314 | 258 | 158 |
| 1200 | 284 | 248 | 170 | 274 | 230 | 150 |
| 1300 | 249 | 221 | 159 | 241 | 207 | 141 |
| 1400 | 220 | 198 | 147 | 214 | 187 | 133 |
| 1500 | 196 | 178 | 137 | 191 | 169 | 125 |
| 1600 | 176 | 162 | 127 | 172 | 154 | 117 |
| 1700 | 159 | 147 | 118 | 156 | 141 | 110 |
| 1800 | 145 | 135 | 110 | 142 | 129 | 103 |
| 1900 | 132 | 124 | 103 | 130 | 119 | 97 |
| 2000 | 121 | 114 | 96 | 119 | 110 | 91 |
| 2100 | 112 | 106 | 90 | 110 | 102 | 86 |
| 2200 | 103 | 98 | 85 | 102 | 95 | 81 |
| 2300 | 96 | 91 | 80 | 95 | 89 | 76 |
| 2400 | 90 | 86 | 75 | 89 | 84 | 72 |
| 2500 | 84 | 81 | 71 | 83 | 79 | 68 |
| 2600 | 79 | 76 | 68 | 78 | 74 | 65 |
| 2700 | 74 | 72 | 64 | 74 | 70 | 62 |

Table 7 Sampling and Demonstrations of Compliance

| Category | Description | Specifications and Expectations |
|---|---|---|
| Sampling General | When Applicable Ports & Platforms, Methods, Notifications and Timing | (A)If necessary, sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in "Chapter 2, Stack Sampling Facilities." 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 Texas Commission on Environmental Quality (TCEQ) Regional Director or his designee.<br>(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.<br>(C) The Regional Office shall be afforded the opportunity to observe all such sampling.<br>(D) The holder of this authorization is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.<br>(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:<br>(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;<br>(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.<br>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.<br>(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.<br>(G) When sampling is required, all Quality Assurance/Quality Control shall follow 30 TAC Ch 25 National Environmental Laboratory Accreditation Conference accreditation requirements. |
| fugitive component monitoring and repair program or leak detection and repair (LDAR) | testing of the new and reworked piping connections | 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. |
| Fugitive monitoring and LDAR | Analyzers | An approved gas analyzer or other approved detection monitoring device used for the volatile organic compound 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 Environmental Protection Agency 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.<br>In lieu of using a hydrocarbon gas analyzer and EPA Method 21, the owner or operator may use the Alternative Work Practice in 40 CFR Part 60, §60.18(g) - (i). The optical gas imaging instrument must meet all requirements specified in 40 CFR §60.18(g) - (i), |

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| | | except as specified in subsection (e)(7) of this standard permit for Best Management Practices. |
| Verify composition of materials | All site-specific gas or liquid analyses | Reports necessary to verify composition (including hydrogen sulfide ($H_2S$) 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. Analysis techniques may include, but are not limited to, Gas Chromatography (GC), Tutweiler, stain tube analysis, and sales oil/condensate reports. These records will document the following: (A) $H_2S$ content; (B) flow rate; (C) heat content; or (D) other characteristic including, but not limited to: (i) American Petroleum Institute gravity and Reid vapor pressure (RVP);(ii) sales oil throughput; or (iii) condensate throughput.<br>Laboratory extended VOC GC analysis at a minimum to C10+ and $H_2S$ analysis for gas and liquids for the following shall be performed and used for emission compliance demonstrations:(A) Separator at the inlet; (B) Dehydration Unit prior to dehydrator;(C) Amine Unit prior to sweetening unit; (D) Tanks for liquids and vapors; and (E) Produced Water or Brine/Salt Water at the inlet prior to storage.<br>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. |
| Engines & Turbines | Initial Sampling of (i)Any engine greater than 500 horsepower;<br>(ii) Any turbine | 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 nitrogen oxide ($NO_X$), carbon monoxide (CO), VOC, and oxygen (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.<br>If there are multiple engines at an oil and gas sites (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.<br>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 United States 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 five years. |
| Engines | Periodic Evaluation | (A) Conduct evaluations of each engine performance every calendar quarter after initial compliance testing by measuring the $NO_x$, CO, and $O_2$ 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.<br>(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 $O_2$, CO, and $NO_x$ 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 $NO_x$ and CO emissions then shall be converted into units of grams per horsepower-hour and pounds per hour.<br>(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.<br>(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 $NO_x$ and CO from any engine, turbine, or other external combustion facility. Diluents to be |

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|---|---|---|
| | | measured include $O_2$ or $CO_2$. Except for system breakdowns, repairs, calibration checks, zero and span adjustments, and other quality assurance tests, the Continuous Emission Monitoring Systems (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 $NO_x$ 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. |
| Combustion Devices | Biennial Testing Any engine greater than 500 horsepower or any turbine | Every two year period starting from the first Initial Compliance Testing, the following facilities shall be retested according to the procedures of the Initial Compliance Retesting shall occur within 90 days of the two year anniversary date of the Initial Compliance Testing. If a facility has been operated for less than 2000 hours during the two year period, it may skip the retesting requirement for that period. After biennial testing, any engine retested under the above requirements shall resume periodic evaluations within the next two calendar quarters. |
| Oxidation or Combustion Control Device | Initial Sampling and Monitoring for performance for VOC, Benzene, and $H_2S$ | Stack testing must be coordinated and approved. Sampling is required for VOC, benzene and $H_2S$ at Region's discretion. The thermal oxider (TO) must have proper monitoring and sampling ports installed in the vent stream and the exit to the combustion chamber, to monitor and test the unit simultaneously.<br>The temperature and oxygen measurement devices shall reduce the temperature and oxygen concentration readings to an averaging period of 6 minutes or less and record it at that frequency. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75% of the temperature being measured expressed in degrees Celsius or ±2.5ºC.<br>The oxygen or carbon monoxide analyzer shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified Performance Specification No. 3 or 4A, 40 CFR Part 60, Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.<br>The oxygen or carbon monoxide analyzer shall be quality-assured at least semiannually using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, §5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive semiannual audits shall occur no closer than four months. Necessary corrective action shall be taken for all CGA exceedances of ±15 percent accuracy and any continuous emissions monitoring system downtime in excess of 5% of the incinerator operating time. These occurrences and corrective actions shall be reported to the appropriate TCEQ Regional Director on a quarterly basis. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director. Quality assured or valid data of oxygen or carbon monoxide analyzer must be generated when the TO is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, inaccurate data, repair, maintenance, or calibration may be exempted provided it does not exceed 5% of the time (in minutes) that the oxidizer operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded. |
| Condensers | Initial Sampling | Effectiveness may require sampling or monitoring upon request by the TCEQ or local programs and is required in all cases where greater than 80% is claimed.<br>Proper monitoring and sampling ports must be installed in the vent stream before and after the condenser. Stack testing shall occur during the worst-case period as specified by the Regional office, including consideration for high ambient temperature and humidity. Stack testing must be coordinated and approved with the Field Operations Division. This testing shall also include any additional control system used for VOC and Benzene, Toluene, Ethylbenzene, and Xylene reductions relied upon for the registration. |

Table 8 Monitoring and Records Demonstrations

| Category | Description | Record Information |
|---|---|---|
| Site Production or Collection | natural gas, oil, condensate, and water production records | Site inlet and outlet gas volume and sulfur concentration, daily gas/liquid production and load-out from tanks |
| Equipment and facility summary | Current process description | As-built plot plan with property line, off-site receptors, and all equipment on-site |
| Equipment specifications | Process units, tanks, vapor recovery units; flares; thermal oxidizers; and reboiler control devices | 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. |
| Site LDAR Program | Details of fugitive component monitoring plan, and LDAR results, including QA, QC | (A) A monitoring program plan must be maintained that contains, at a minimum, the following information:<br>(i) an accounting of all the fugitive components by type and service at the site with the total uncontrolled fugitive potential to emit estimate;<br>(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.<br>(B) Records must be maintained of all monitoring instrument calibrations.<br>(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..<br>(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(g)-(i). The log must contain, at a minimum, the following:<br>(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.<br>(E) If the owner or operator is using the Alternative Work Practice specified in 40 CFR §60.18(g) - (i), the records required by 40 CFR §60.18(i)(4).<br>(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.<br>(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.<br>(H) A check of the reading for any pressure-sensing device to verify rupture disc integrity shall be performed weekly. |
| Minor Changes | Additions, changes | Records showing all replacements and additions, including summary of emission type and |

| | | |
|---|---|---|
| | or replacement of components or facilities | quantities. |
| Equipment Replacement | Like-Kind replacement | Records on equipment specifications and operations, including summary of emissions type and quantity. |
| Process Units | Glycol Dehydration Units | Records of Operational Monitoring and Testing Records (Glycol Solution, Contact Pressure, Temperature, and Pump Rate) |
| | Process Separators | Records of Operational Monitoring and Testing Records (Worst Case Pressure) |
| | Oil/Water Separators used in pressurized system vs. ambient conditions receiving a pressurized solution | Records of Operational Monitoring and Testing Records (Worst Case Pressure) For PBR no ambient requirements. |
| | Amine Units | Records of Operational Monitoring and Testing Records (Amine Solution, Contact Pressure, Temperature and Pump Rate) |
| Boilers, Reboilers, Heater-Treaters, and and Process Heaters | Combustion | Records of Operational Monitoring and Testing Records<br>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 |
| Internal Combustion Engines | Combustion | Records of Appropriate Operational Monitoring and Testing Records<br>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.<br>See fuel records below |
| Gas Fired Turbines | Combustion | Records of Appropriate Operational Monitoring and Testing Records<br>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 |
| Fuel Records | VOC and Sulfur Content | For each separate fuel gas use at the site, the fuel usage and VOC content if the VOC content was used in emission estimation.<br>If field gas contains more than 1.5 grains (24 ppmv) of $H_2S$ or 30 grains total sulfur compounds per 100 dry standard cubic feet, the operator shall maintain records, including at least quarterly measurements of fuel $H_2S$ and total sulfur content, which demonstrate that the annual $SO_2$ emissions do not exceed limitations |
| Tanks/Vessels | Color/Exterior | Records demonstrating inspection and maintenance of paint color and vessel integrity. |
| Storage Tanks Loading | Each Loading Spot Emission and emission potential | 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. |
| Truck Loading | All Types | Records indicating type of material loaded, amount transferred, duration of transfer, method of transfer, condition of tank truck before loading. |
| | Vacuum Trucks | Note loading with an air mover or vacuum. No additional record is needed where a vacuum truck uses only an on-board or portable pump to push material into the truck. |
| | Controlled Loading | Where control is required note the control that is utilized. |
| | Tank Truck Certification | Records of tank truck certifications and testing. Records are only required if connection to control is used and credit is claimed for certified truck use. |
| 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.<br>Cooling water VOC concentrations above 0.08 parts per million by volume (ppmv) indicate |

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| | | 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 record integrity of drift eliminators annually, repairing as necessary. If a maximum solids content must be maintained through blowdowns to meet particulate emission rate limits, cooling water shall be sampled for total dissolved solids (TDS) once a week at manned sites or monthly at unmanned sites and maintain records of the monitoring results and all corrective actions. |
| Alternate Operations | Planned MSS or other operational variations including control downtime | Records of redirection of vent streams during primary operational unit or control downtime, including associated alternate controls, releases and compliance with emission limitations. |
| Planned Maintenance, Start-up, and Shutdown (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 to meeting all the requirements in Table 7, keep records of the following: (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:<br>• Alternate operational scenarios or redirection of vent streams;<br>• Pigging, purging, and blowdowns;<br>• 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;<br>• Degassing or purging of tanks, vessels, or other facilities;<br>• Management of sludge from pits, ponds, sumps, and water conveyances;<br>• Amine and other treatment chemicals replacement (except glycols);<br>• Hot oil treatments.<br>• Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance;<br>• Boiler refractory replacements and cleanings;<br>• Heater and heat exchanger cleanings;<br>• Cleaning of separator, amine, and dehydrator dump valves;<br>• Amine filter replacements;<br>• Turbine hot section swaps;<br>• Pressure relief valve testing, calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens. |
| Control Devices | Flare Monitoring | Basic 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, pilot flame, or auto-ignition 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.<br>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. |
| Control Devices | Thermal Oxidation and Vapor Combustion Performance Monitoring Basic | Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits.<br>Basic monitoring is a thermocouple or infrared monitor that indicates the device is working.<br>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 degrees Fahrenheit 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. |
| Control Devices | Condensers | Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits.<br>Basic monitoring is 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. |
| Control Devices | Vapor Capture and Recovery | Monitoring and records are required only where the piping and equipment is necessary for the site to meet emission rate limits.<br>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.<br>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 Devices | Control with process combustion or heating devices (e.g. reboilers, heaters & furnaces) | Monitoring and records are required only where the equipment is necessary for the site to meet emission rate limits. 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.<br><br>Basic monitoring is any continuous monitor that indicates when the flame in the device is on or off. 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.<br>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 $O_2$ 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 | As Applicable | 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

| **Engine Type** | **Engine Size** | **Manufacture Date** | **$NO_X$ (g/bhp-hr)** | **CO (g/bhp-hr)** | **VOC (g/bhp-hr)** |
|---|---|---|---|---|---|
| **Rich Burn** | less than 100 hp | All dates | no standard | no standard | no standard |
| | greater than or equal to 100 hp | Before January 1, 2011 | 2 | 3 | 1 |
| | greater than or equal to 100 hp | After January 1, 2011 | 1 | 3 | 1 |
| | After January 1, 2020 and regardless of manufacture date, no rich burn engine greater than or equal to 100 hp authorized by this rule shall emit $NO_X$ in excess of 1.0 g/bhp-hr. 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 equal to 500 hp | Before September 23, 1982 | 8 | 3 | no standard |
| | | Before June 18, 1992 and rated less than 825 hp | 8 | 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 |
| **Lean Burn, 4SLB** | less than 500 hp | Before July 1, 2008 | no standard | no standard | no standard |
| | | On or after July 1, 2008 | 2 | 3 | 1 |
| | greater than or 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, 2030 and regardless of manufacture, no 4-stroke lean burn engines authorized by this rule shall emit $NO_X$ in excess of 2.0 grams per brake horsepower per hour (g/bhp-hr). 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 $NO_X$ or CO in excess of 3.0 g/bhp-hr. | | | | |