The Texas Commission on Environmental Quality (TCEQ, agency, or commission) adopts the repeal of §106.352 and simultaneously adopts new §106.352.

The repeal of §106.352 is adopted *without change* as published in the August 13, 2010, issue of the *Texas Register* (35 TexReg 6937), and will not be republished. New §106.352 is adopted *with changes* to the proposed text and will be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED 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: updating administrative and technical requirements; making appropriate changes to registration or notification requirements; ensuring that air emissions from specific facilities are protective of public health and welfare; including practically enforceable record requirements; authorizing planned maintenance, startup, and shutdown (MSS) activities; and allowing 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 commission evaluations of 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 and updated based on current scientific information, and to properly regulate all operations.

The oil and gas industry appears to be in the midst of a new boom. New technologies have made hydraulic fracturing an economical possibility and have allowed industry to tap into shale gas that was previously far too expensive to extract. This new boom is the result of technologies and methods that have evolved over the years. While the technology for drilling wells and producing oil and gas has evolved, the laws governing this industry have not. Texas still operates under the same PRB that it adopted in 1997. The rule adopted in 1997 is a relic from Standard Exemption No. 66, which governed Oil and Gas Facilities, effective in 1986. Essentially, Texas is applying 25-year old rules to an industry where science and technology are evolving on a daily basis. Not only has science and technology allowed us to tap into previously unattainable resources, it has also allowed us to better understand the effect of oil and gas drilling and production operations have on public health and the environment. Again, the most up-to-date science and emission detection systems have greatly evolved over the past 25 years. Unfortunately, our laws have not. While the Standard Exemption reflected current science in 1985, it does not reflect current science in 2010. The science of 2010 dictates that the PBR and standard permit be updated in order to allow increased air emissions and protect public health and the environment.

In a concurrent action, the commission is issuing 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 are adopted and issued to provide an updated, comprehensive, and protective authorization for many common OGS in Texas. The new PBR and standard permit include operating specifications and emissions limitations for typical equipment (facilities) during normal operation, which includes production and planned MSS. The 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 commission has established a hierarchy of authorization mechanisms. The most negligible sources are covered under 30 TAC §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 30 TAC Chapter 106. The PBRs are rules with general and specific requirements promulgated by the commission. PBRs are usually specific to an industry or activity. A facility or group of facilities 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 30 TAC 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 new major sources or major modifications at existing major 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 new PBR provides an updated, comprehensive, and protective authorization for many common OGS in Texas. The PBR was developed considering current emission capture and control equipment and includes specifications and limitations for typical equipment (facilities) during normal operation, including production as well as planned MSS.

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 PBR and standard permit address the appropriateness of multiple authorizations at one contiguous property. This PBR also includes revised criteria for registration and scope of protectiveness reviews for changes at existing, authorized sites. The commission is not requiring that all facilities at a site be authorized under one type of permit, merely, that all dependent oil and gas facilities at a site be authorized under one type of permit. The purpose of standard permits and PBRs is twofold: 1) to provide a streamlined application process for industry that allows for greater flexibility and a speedier application process; and 2) to allow the commission to more efficiently process permit applications that do not require a case-by-case review. If a group of dependent facilities cannot be authorized by a single PBR or standard permit at a given site, as some commenters have suggested, the only other option would require that each one of the discrete emissions producing sources would need to obtain an individual permit. This is contrary to the very purpose for which PBRs and Standard permits were established. Requiring each individual emission source located on one property to obtain a separate PBR or standard permit would waste both industry's and the state's time and resources. This new PBR also includes revised criteria for registration and scope of protectiveness reviews for changes at existing, authorized sites. Furthermore, requiring all oil and gas facilities at a site to be permitted under one authorization prevents what is known as "stacking." PBRs can only be authorized for facilities that do not exceed the 25/250 limit found in §106.4(a)(1). It is easy to see how stacking multiple PBRs at one site would allow an operator to circumvent the intent and purpose of the 25/250 limit. The adopted rules would prevent a site from circumventing the 25/250 limit and require it to obtain the appropriate Standard permit or case-by-case NSR permit.

Many stakeholders commented that a periodic renewal of PBR registrations for OGS should occur. At this time, the commission is not adopting 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.

Any authorization which requires federal preconstruction authorization under the prevention of significant deterioration (PSD) or the nonattainment new source review (NNSR) requirements of 40 Code of Federal Regulations (CFR) Part 51 or Part 52 as applicable may not be authorized under this PBR. 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) as applicable. 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).

As stated earlier in this preamble, two of primary goals of the PBR study are to verify that all general authorizations of the commission, such as PBRs and standard permits, are protective of public health and welfare and to recommend rule changes to ensure or improve their continued protectiveness. To achieve these goals, the commission conducted an impacts evaluation to verify that individual PBR claims will not adversely impact public health and welfare.

The following are summaries of the health impacts of the regulated pollutants:

Benzene

Breathing high concentrations of benzene for a short period of time (hours) can cause dizziness, nausea, headache, and drowsiness. Repeated exposure to high concentrations for several days may adversely affect the blood. Breathing high concentrations of benzene every day for years may adversely affect your bone marrow and blood and may increase your risk for a specific type of leukemia.

Hydrogen Sulfide (H_2S)

Short-term exposure to low concentrations of hydrogen sulfide may cause irritation to the eyes, nose, or throat. It may also cause difficulty in breathing for some asthmatics. Brief exposures to high concentrations of H_2S (greater than 500 parts per million (ppm)) can cause a loss of consciousness. Repeated or long-term low-level exposures to H_2S may also cause signs and symptoms such as headache, fatigue, dizziness, and irritability; or neurological effects. H_2Salso poses an offensive rotten-egg odor with an odor threshold concentration (0.008 ppm) well below the levels cause adverse health effects.

Nitrogen Dioxide (NO_2)

Short-term exposure to low concentrations of NO_2 can cause mild eye, mucous membrane, and respiratory tract irritation. Brief exposures to high concentrations of NO_2 can cause the tightness of chest or lung edema. Repeated or chronic NO_2 exposure may cause chronic bronchitis, lung edema, and emphysema of the lungs. NO_2 has a distinct odor with an odor perceptible level at 0.11 ppm.

Sulfur Dioxide (SO_2)

Short-term exposure to low concentrations of SO_2 can cause respiratory (mucous membrane) irritation. Brief exposures to high concentrations of SO_2 can cause upper airways constriction, irritation and complaints of discomfort, cough, and loss of lung function. Excessive and chronic exposure to SO_2 can cause reductions in lung function, thickened mucous layer in the trachea, and chronic respiratory disease. SO_2 has a strong suffocating odor with an odor perceptible level approximately at 0.5 ppm.

For each type or group of typical OGS facilities and activities, the commission 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 and are they protective of public health and welfare? In addition, for dependent 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 and are they 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 was available. Research in many areas has continued for several years, and the results of those efforts are included in this adoption 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 commission 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, or opinions which were further considered by the commission. A summary of the most common comments and how they may have been considered is available through the commission Web page for this rule project.

Additional information was requested from stakeholders or explored by the commission to help develop this rule. Where sufficient information was available, the commission considered factors such as emissions, potential impacts, BMP, MSS, and control technologies and used them to develop this rule 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 systems, 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, H_2S scavenger chemical reaction vessels for sulfur removal, 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, gas recovery units. 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 vapor recovery units (VRU). 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 standard permit for OGS available through the commission's Web page.

The commission 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 commission 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; storage of products in locations/under conditions that will preserve their shelf life; maintenance of tight fitting lids and bungs on containers (even those that are empty); storage of containers in such a way as to allow for visual inspection for corrosion and leaks; stacking containers in a way to minimize the chance of tipping, puncturing, or breaking; storage of packages, etc., properly to prevent damage or contamination; protection of items stored outdoors from temperature extremes, rain, snow, wind, 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 commission encourages all companies in the oil and gas industry to consider implementing these or any other measures which help reduce and eliminate pollution.

SECTION BY SECTION DISCUSSION

The commission has completed a comprehensive evaluation of emissions and impacts from OGS (see details in the Air Quality Standard Permit for Oil and Gas Handling and Production Facilities technical summary) and is adopting the new PBR and a concurrent standard permit for OGS to ensure these authorization mechanisms effectively regulate emissions. The adopted 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 that do not exceed 250 tons per year (tpy) of NO_X and carbon monoxide (CO), 15 tpy of particulate matter with diameters of 10 microns or less (PM_{10}); or 10 tpy of particulate matter with diameters of 2.5 microns or less ($PM_{2.5}$), 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 new PBR authorizes two distinct levels of OGS production facilities and associated MSS operations. The first level is for the smallest of insignificant emissions sites. The second level is still for insignificant sites, but ones with higher emissions and more complex operations.

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

Subsection (a) outlines the applicability of registrations under this new PBR. The 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. This authorization may be used 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 this PBR.

The majority of the PBR requirements are only applicable to new facilities or modifications that increase emissions 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 (Texas Constitution, Article 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); Texas Government Code, §311.022 (stating statutes are prospective unless expressly made retroactive)). Thus, when the legislature grants rulemaking authority to an agency, this same presumption applies. 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.

The commission has modified subsection (a) to include the requirements for the applicability dates for the Barnett Shale. The commission, like all state agencies, is faced with helping resolve substantial budget deficits and has limited resources. To ensure an accurate and comprehensive authorization system, agency resources must be focused on all OGS and the highest volume are for facilities located in the growing shale areas. Therefore, the commission has included subsection (a)(1) which establishes the criteria that new projects and related facilities located in the Barnett Shale (Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Stephens, Somervell, Tarrant, and Wise Counties) will be applicable to subsections (a) - (k) on or after April 1, 2011. This area has been chosen due to the high volume of current and anticipated drilling and its close proximity to dense urban populations. The phased implementation will also give the commission an opportunity to evaluate its administration of the new rule and its effectiveness. For all other new projects and related facilities only subsection (l) will be applicable until January 5, 2012, after which subsections (a) - (k) are applicable.

Subsection (a)(2) requires that all oil and gas facilities be authorized under one Oil and Gas PBR 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)(8) of this section are met to ensure comprehensive protectiveness of this authorization and prevent partial permitting or circumvention of these PBR requirements.

Subsection (a)(2) 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 planned 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 new section for the authorization of planned MSS activities. The requirements included in the 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 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 site's underlying 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)(3) 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)(4) prohibits the use of this section to authorize upsets, emergencies, or malfunctions. The commission 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 section does not regulate methane, ethane, or carbon dioxide (CO_2). If the federal or state government promulgates requirements for these air pollutants, separate rules and requirements will have to be met following subsection (a)(3).

The commission's intent in adopting 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 commission will meet state and federal air quality standards and guidelines based on an evaluation of all potential emissions.

Subsection (b) describes the scope of the PBR and defines the terms which are critical to ensuring the understanding or, and consistency with the expected uses of this PBR, including federal permit applicability, PBR registration, and protectiveness review and emission limitations.

The definition of facility is adopted in subsection (b)(1) for clarity, and does not change any of the commission's other rules on the definition of facility. This term is included since there are frequent misunderstandings regarding the use of the term "facility." Many customers and the general public use the word "facility" to describe entire plants or groups of equipment, not each individual source of emissions. THSC, §382.003(6) specifically excludes well tests from the definition of facility. State law further narrows the exception in THSC, §382.003(13) and limits the well testing time to 72 hours.

Subsection (b)(2) defines receptor for the purpose of determining the most appropriate emission limit which is based on the distance to the defined receptor. For the air contaminants with potential health effects, distance measurements will be taken from the source of the emissions to the nearest off-property receptor. Receptor has been defined to include structures which are in use as a single or multi-family residence, school, day-care, hospital, or place of worship at the time this section is claimed. In response to comments, the definition of receptor has been expanded to include certain businesses. These receptors are included if they are occupied regularly as those in the general public who occupy these structure may be exposed for extended periods of time. The business definition however excludes those businesses whose primary function is oil and gas production, as the emissions they are exposed to are the same - and in much higher concentrations - as the site seeking authorization may be emitting. The reason for including the phrase "at the time this section is claimed" is to provide certainty as to evaluating what is considered a receptor at the time this PBR is claimed.

Residence is 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 COMMISSION 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 it is generally self-evident whether or not a structure is a residence. In some cases, questions may arise as to the type of a structure, and if it should be considered a receptor, located near a facility when determining its compliance with applicable distance requirements. If necessary, a determination shall be made by the commission regarding whether or not a structure is a residence. The commission may consider factors and circumstances specific to the situation when 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 the frequency of the use of the 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 rights granted to surface owners, but these rights are not always held by the same person. To get to their mineral property, mineral owners typically, coordinate with surface owners.

The PBR states that all measurements from emission sources to receptors shall be taken from the project location, which requires registration under the PBR, to the nearest receptor. The locations listed above are considered to be areas where the general public may congregate or be exposed to emissions for extended periods of time, and the PBR will ensure no negative effects occur at receptors.

The definition of receptor and language are consistent with the current air quality standard permit for permanent rock and concrete crushers with certain additions. The original language is from House Bill 2912, 77th Legislature, 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. However, the commission has chosen to include not only single or multi-family residences but, day-cares and hospitals in its definition of receptor because the inhabitants of these structures are typically more susceptible to the effects of air emissions from pollutants of concern regulated by this PBR. Other structures such as restaurants, stores, businesses, and parks are not included in the definition for this rule package. In many cases, these structures are not occupied for long periods of time. When they are used for extended periods of time, the inhabitants are generally less susceptible to the effects of air emissions or are better able to remove themselves from these sources of emissions.

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 the purposes of the determining major sources under the federal operating permits program. Following comments received 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 of the same person (or persons under common control), and located on contiguous or adjacent properties. The commission has revised this definition in order to be more consistent with the definition in 30 TAC Chapter 122. In no way do the provisions of this subsection allow owners or operators to avoid federal aggregation regulations, if those regulations and policies are applicable. Specifically, an owner or operator may not apply the provisions of this subsection until it has been confirmed that the site does not trigger PSD or NNSR applicability.

The federal operating permit definition of OGS is included in subsection (b)(4) for emphasis, and does not change any of the commission's other rules on the definition of 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 commission 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 the limitations outlined in that document.

Subsection (b)(5) highlights the limits and scope for state authorization purposes and defines a project under this section as meeting all requirements of this section prior to construction or implementation of changes. These new or changing facilities must be operationally dependent to existing, unchanging oil and gas facilities as referenced in subsection (b)(5)(A). In the past, no clear definition of project had been provided. In response, the commission has revised the rule and defined "project" consistent with other NSR permitting actions. Registration, and all applicable requirements, under this section are triggered when a physical or operational change to existing authorized facilities or group of facilities will increase the potential to emit over previously certified emissions limits as referenced in subsection (b)(5)(B) or (C). Additionally, any operator who adds pieces of equipment to an existing site, such as a site operating under a historical standard exemption or PBR, after the effective date of the revised PBR will be required to meet the new requirements for only the newly installed facilities. This includes replacements of facilities. It is imperative for companies to address certified emissions limitations in order ensure that any change with a potential to increase emissions at an existing site will not trigger the new rule requirements.

Subsection (b)(6) specifies the scope of a registration. As with the major source determination, all OGS facilities should be included. Under this PBR, the facilities which are covered under a single PBR registration must be located no more than 1/4 mile apart and should be operationally dependent as listed in subsection (b)(6)(A). The commission considers that combinations of facilities and equipment, which are constructed and operated 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 a 1/4 mile from the new facilities or groups facilities that have the potential of increasing emissions as listed in subsection (b)(6)(B) - (E). 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. The commission has also revised the scope of "registration" and established a fixed boundary in order to provide certainty to the regulated community and the public of which facilities are included in the registration. Finally, to ensure a complete evaluation within the established boundaries, fugitive emission releases must be included for purposes of emission limits of this subsection. Subsection (b)(6)(G) limits all OGS registrations under this section to a cumulative emission limit. The rule establishes a site-wide emission limit for all OGS facilities under a single registration to 250 tpy NO_X or CO, 15 tpy of PM_{10}, or 10 tpy of $PM_{2.5}$, or 25 tpy of any other air contaminant.

As a result of the site-wide emission limits, if piping or fugitive components are the only connection between facilities, and the distance between the facilities is only the piping and fugitive components, then the facilities will be considered separate when determining the 1/4 mile separation for registration as listed in subsection (b)(6)(C). Additionally, the boundaries of the registration become fixed at the time this section is claimed and registered. No individual facility may be authorized under more than one registration as listed in subsection (b)(6)(D). This requirement will ensure that there will be no boundary creep or daisy-chaining as modifications occur at the site, thus giving certainty to compliance demonstrations. Any facility or group of facilities authorized under an existing PBR registration which is operationally dependent on a project must be revised to incorporate the project. 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 subsections (i) and (k) of this section (the protectiveness review and planned MSS requirements) as listed in subsection (b)(6)(E). A registration may include facilities which are claiming historical standard exemptions and PBRs, as well as projects that will be claimed under this section. Existing authorized facilities or groups of facilities at an OGS under this section, which are not changing the certified character or quantity of emissions, must only meet the protectiveness review and planned MSS requirements of this section as listed in subsection (b)(6)(F). Finally, facilities at an OGS registered under this section must collectively emit less than or equal to 250 tpy of NO_X or CO, 15 tpy of PM_{10}; or 10 tpy of $PM_{2.5}$; and 25 tpy of VOC, sulfur dioxide (SO_2), H_2S, or any other air contaminant as listed in subsection (b)(6)(G).

Subsection (b)(7) addresses the only two requirements of this rule to existing, unchanged facilities. In order to ensure a comprehensive accounting for all facilities which claim this PBR or any historical version of this PBR, the commission is requiring a notification by all existing sites by January 1, 2013. In addition, this requirement addresses planned MSS at existing 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 PBR relies on an assessment and evaluation of anticipated MSS activities. It is only under the new PBR requirements and limits that MSS is authorized since no previous version of the OGS PBR clearly reviewed these emissions. There is substantially more information about these emissions, operations, and activities than at any previous point in the past, and the commission is requiring that these emissions demonstrate compliance with the protectiveness review. It should also be noted that MSS is not currently required to be authorized nor will sites lose their existing affirmative defense opportunities until January 5, 2012. Adding the annual emission release quantities to production releases, and confirming that all requirements of PBRs continue to be met, this evaluation for all new and existing sites also ensures that federal operating permit applicability for traditional criteria air contaminants is assessed in accordance with EPA and TCEQ rules and policies.

Subsection (b)(8) addresses the obligation of permit holders to ensure the protection of public health and welfare, and demonstrate compliance with applicable ambient air standards. Subsection (k) requires companies to demonstrate protectiveness based on an assessment of peak and cumulative emissions which will not cause, or contribute to, air pollution in excess of any maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this section applies, national ambient air quality standard in any air quality control region, or any other applicable emission standard or standard of performance under Chapter 106. 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 the fundamental intent of the TCAA. Hourly emission limits are necessary in order to ensure protection of public health from short-term exposure. Hourly emission limits are a necessary part of this rule since both ambient standards and ESL guidelines exist on an hourly basis, therefore a direct confirmation is the most appropriate and practically enforceable rule requirement.

Subsection (b)(8)(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 PBR requires an impact analysis be done on a contaminant-by-contaminant basis for any project net emission increases. 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 the protectiveness evaluation may establish more stringent limits than otherwise required by the PBR, and will ensure that property lines and receptors in close proximity to the OGS have been evaluated.

Subsection (b)(8)(B) establishes limits on hourly and annual emissions based on the most stringent of subsections (g), (h), or (k). There are numerous state and National Ambient Air Quality Standards (NAAQS) applicable to the emissions associated with an OGS, including nitrogen dioxide (NO_2) (hourly 188 micrograms per cubic meter ($\mu g/m^3$), annual NAAQS, 100 $\mu g/m^3$; CO (hourly NAAQS 40,000 $\mu g/m^3$ and eight-hour NAAQS 10,000 $\mu g/m^3$), SO_2 (new hourly NAAQS 196 $\mu g/m^3$, three-hour NAAQS 1,300 $\mu g/m^3$, 24-hour NAAQS 365 $\mu g/m^3$, and annual NAAQS 80 $\mu g/m^3$, most stringent state 30-minute standard 715 $\mu g/m^3$), PM_{10} (24-hour NAAQS 150 $\mu g/m^3$, annual NAAQS 50 $\mu g/m^3$), $PM_{2.5}$ (24-hour NAAQS 35 $\mu g/m^3$, annual NAAQS 15 $\mu g/m^3$). H_2S does not have a NAAQS, but is regulated by 30 TAC Chapter 112, Control of Air Pollution from Sulfur Compounds (statewide standard is 162 $\mu g/m^3$, with the most stringent state standard at 108 $\mu g/m^3$). Also present at OGS are contaminants that include, but are not limited to, natural gas, condensate, crude oil, benzene, and other common contaminants. These contaminants are limited to 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 - 5F in subsection (m) 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) and applicable for any location in the state. 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.

Based on comments, the initial modeling analysis was updated to include predicted concentrations out to a distance of 5,500 feet for all sources. The combustion unit modeling was updated to include additional ranges of engines. Subsequent review of the pipeline blowdowns parameters used in the previous analysis were determined not to be representative of the activities occurring. The compressor blowdown parameters were determined to be representative for both pipeline and compressor blowdowns. The pipeline blowdown results are no longer necessary and are removed from the results. This modeling supersedes previous modeling results and the appropriate tables were updated and results used to develop reasonably conservative emission limits. Each source was modeled separately at a unitized emission rate of one pound per hour. This technique determined a unitized maximum predicted ground-level concentration (GLCmax) for each source in units of micrograms per cubic meter per pounds per hour (lb/hr). To determine the allowable emission rate for each contaminant, the applicable ESL or standard can be divided by the generic GLCmax. The Tables represent modeled concentration from the following sources.

Fugitive sources comprise all fugitive emissions from a representative OGS. Fugitive emissions were represented as three sources: a circular area source with a 1-meter release height and 9-meter diameter; a point source with a 3-meter release height; and a point source with a 6- meter release height. Lowest level fugitive emissions (at about 1- meter) occur at various locations within a plant site. Since the resulting emissions are usually well distributed throughout a site and not released through standard stacks, an area source representation is appropriate. The circular area source type was selected to minimize bias of any one wind direction or source orientation. Similarly, the loading and storage tank fugitive emissions do not release to the atmosphere through standard stacks but generally are not distributed throughout a site. The loading and tank fugitive emissions are represented by the point source characterization using pseudo-point source parameters and are co-located with the circular area source.

Process vent stacks sources are representative of stacks or 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. Seven complex OGS were reviewed resulting in a compilation of source parameters for 21 facilities. Of the 21 facilities reviewed, stack heights ranged from 12 feet to 39 feet, stack diameters ranged from 0.05 to 3.5 feet, exit velocities ranged from 1 to 90 feet per second (ft/sec), and temperatures ranged from 80 degrees F to 800 degrees F. Reasonable worst-case parameters for air dispersion modeling were derived from this review. A stack flow rate of 500 actual cubic feet per minute (acfm) at 120 degrees F was used in the analysis. A stack diameter of 1 foot was modeled with an exit velocity 10.6 ft/sec. The stack heights modeled ranged from 10 feet to 60 feet. These sources were represented as point sources.

Compressor blowdown stacks and pipeline blowdown are representative stacks used for the temporary venting of a gas compressor or 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 reasonable worst-case modeling parameters for 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. It was determined that stack-tip downwash was not appropriate due to the small diameter of the stacks and the short duration of the activity (generally less than 30 minutes).

After subsequent review of the blowdown parameters used in the previous analysis, the modeled parameters were determined not to be representative of the activities occurring under high pressure. The modeling results were updated to include more representative parameters for blowdowns with pressure greater than or equal to 30 pounds per square inch gauge (psig). Sources were modeled as representative stacks used for the temporary venting of a gas compressor or temporary venting of a gas pipeline under high pressure. Reasonable worst case stack parameters were derived from a review of industry sources, and two source configurations were modeled. A stack with a height of 6 feet and a diameter of 4 inches was modeled with an exit velocity of 550 ft/sec, and a stack with a height of 10 feet and a diameter of 6 inches was modeled with an exit velocity of 550 ft/sec. A minimum stack height of 6 feet is expected due to safety concerns. The initial period of the blowdown will have the greatest amount of pressure resulting in the largest exit velocity and highest plume rise. Near the end of the blowdown period, the pressure will have decreased resulting in less exit velocity and less plume rise. For this reason, an exit velocity of 550 ft/sec is reasonable given the initial velocity expected is 1100 ft/sec and will decrease over time as the pressure decreases. It was determined that stack-tip downwash was not appropriate due to the small diameter of the stacks, high exit velocity, and the short duration of the activity (generally less than 30 minutes). These higher pressure (>30 psig) blowdown scenarios were evaluated and demonstrated dramatically increased dispersion parameters, reducing potential impacts.

For higher pressure blowdowns when a pressurized gas is released to atmosphere the mass flow rate is proportional to the pressure differential but the exit velocity remains chocked at sonic velocity (approximately 1,100 ft/sec) until the upstream piping pressure just before the release falls to below 30 psig. The model was run at a conservative exit velocity of (550 ft/sec) one half of the sonic velocity through a 6 inch diameter opening to the atmosphere directed vertically. Based upon the submitted information, two release scenarios for a vertical 6 foot and a 10 foot release height for higher pressure blowdowns from pipelines were developed and added to subsection (g)(3) and (h)(3) in the PBR and subsection (h)(3) in the standard permit. These scenarios are for pressurized gas that is rapidly released with the piping intial pressure exceeding 30 psig. These scenarios assume no liquids are released, only vapors.

Combustion units are representative of all internal combustion processes associated with reciprocating engines. Reasonable worst-case stack parameters were derived from an industry review of sources. Six engine ranges are represented in the modeling. 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 engine ranges and exhaust parameters are listed in the following.

Figure 1: 30 TAC Chapter 106 - Preamble

Table A. Engine HP ranges and Exhaust parameters			
Source Group	Horsepower Range	Flow (acfm)	Diameter (inches)
ENG1	Less than 250	984	6
ENG2	250 to 500	2459	8
ENG3	500 to 1000	4920	10
ENG4	1000 to 1500	8198	12
ENG5	1500 to 2000	11842	12
ENG6	Greater than 2000	16330	16

Thermal destruction devices are representative of all processes associated with flares and other thermal destruction devices. Reasonable worst-case stack parameters were derived from a review of industry thermal control devices. Numerous authorization 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} / $PM_{2.5}$ being emitted. When a process stream is being destroyed, slightly higher amounts of these pollutants are released. In addition, when flares are 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) convert to SO_2, and, depending on the waste streams, may potentially emit significant amounts of this criteria air contaminant. Flares in particular continue to be reviewed for effectiveness, especially in situations when large masses of waste gases are sent to these units in short periods of time. These and similar issues on effectiveness will continue to be evaluated in separate actions by the commission.

Emission rates and stack parameter data for thermal destruction devices were gathered for approximately 20 sites. The assumptions used in developing the reasonable worst-case parameters were a minimum energy value of 200 British thermal unit per standard cubic foot (btu/scf) in accordance with NSPS in 40 CFR §60.18, and a minimum height of 20 feet. Five sites of those reviewed had low flow values ranging from 691 to 3,129 standard cubic feet per minute (scfh). These were averaged to derive a reasonable low flow value of 2,400 scfh. Flares were modeled as point sources with temperature of 1,273 Kelvin (K) (1,832 degrees F), exit velocity of 20 meters/sec (66 ft/sec), release heights of 20, 30, 40, 50, and 60 feet, and a diameter of 6 inches. The values for the exit temperature and velocity are default values for modeling flares. Many sites have flares or similarly designed thermal destruction devices to control VOCs during production and planned MSS. Since the dispersion characteristics of these units have higher flow, thermal buoyancy, and usually higher release heights to process vents, these factors combine to have greater dispersion, and thus higher emissions would be allowed.

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, every one hundred feet out to 3,000 feet, and every five hundred feet out to 5,500 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 analysis is primarily for short-term concentrations, this 5-year data set would include worst-case short-term meteorological conditions that could occur anywhere in the state. The wind directions were set at 10 degree intervals to coincide with the receptor radials. This would provide predictions along the plume centerline which is a conservative result.

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

The modeling analysis document can be found through the Air Permits Remote Document Server, in the New Source Review General (NSRG) library under document number 10989. The modeling files can be found in the NSRG library under document number 10991. 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 standard permit and PBR as one of three possible tools available to the regulated community to demonstrate protectiveness.

The commission expanded the evaluation to approximately 1 mile (5,500 feet) based on three factors: 1) the commission's consideration of distance limits for contiguous properties and operationally related facilities; 2) the conservative nature of the model and modeling approach as previously discussed; and 3) 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 generic tables to estimate the maximum acceptable hourly emissions that would not exceed any ambient standard or ESL. Additionally, the commission reviewed hundreds of OGS PBR and standard permit registrations and reports and set reasonable emission rates and site-wide caps based on the conservative predictions from the entire receptor grid of the impacts analysis. The commission restricted emission changes at existing OGS facilities to ensure continuing protectiveness of previously authorized facilities. The following paragraphs summarize the results of the commission's review.

Air dispersion modeling was performed for a variety of emission source types (for example fugitives, flares, and engines) based on reasonable modeling parameters specific to each type. This modeling is not pollutant specific, meaning that it can apply to multiple compounds. Since the modeling was run with a 1 lb/hr basis, the units of the modeling results are micrograms per cubic meter per pound per hour, which is a concentration over a mass rate. The model was set up to give a result for combinations of emission release heights (based on reasonable height ranges for the type of emission source) and distances out to 5,500 feet. These results are shown in the PBR and standard permit Tables 2-5F in subsection (m) of each document.

These generic modeling results were combined with the most stringent concentration limits (either an ESL, or ambient air quality standard concentration) for each pollutant in order to come up with an emission rate in lb/hr. This was done by dividing the ESL or ambient air quality standard by the modeling result; a concentration divided by a concentration over a mass rate equals a mass rate. Both short-term/hourly and long-term/annual ESLs and ambient air quality standards were considered.

To establish the emission limits for the PBR and standard permit, the commission looked at the sources that had the highest potential emissions of each compound. The commission then looked at the emissions at certain release heights and distances. The release heights chosen vary based on what is reasonable for each emission source type; the distances chosen are approximately 1/4 mile for PBR Level 1, 1/2 mile for PBR Level 2, and 1 mile for the standard permit.

The PBR and standard permit limits are emission caps. The commission is also asking applicants to demonstrate protectiveness for benzene, H_2S, SO_2, and NO_X based on how close a site's emissions are to property lines and receptors. This means that in order to demonstrate protectiveness, a site may be limited to even less than these caps.

The following discussion covers the logic of how the air contaminants of concern at OGS were evaluated to determine that NO_X, SO_2, H_2S, and benzene are the only air contaminants that need to be included in the pollutant by pollutant protectiveness demonstration of subsection (k). It is important to note that air contaminants not required to be included in the registration-specific protectiveness review are still held to the limits of the rule, just not a more stringent standard based on the protectiveness review. The commission has determined that as long as protectiveness of these specified air contaminants is demonstrated, it can be assumed that the emissions of other contaminants are protective as long as they meet the emission limits set by the rule. For this determination, the generic modeling results were used to create pollutant specific tables that show the emission rates of specific pollutants determined to be protective of public health and welfare and meet applicable ambient air quality standards (at the listed release height and distance from the emission source to the receptor or property line). The emission rates (lb/hr) are calculated by dividing either the ESLs or ambient air quality standards ($\mu g/m^3$) applicable to each specific pollutant by the modeling results ($\mu g/m^3$) per (lb/hr). Both short-term and long-term ESLs and air quality standards were considered. The most stringent ESLs and air quality standards were used in all analyses.

CO has a one-hour ambient air standard of 40,000 $\mu g/m^3$ and an eight-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 the conservative impacts evaluation table for engines, at the shortest distance (50 feet) and the lowest dispersing stack (8 feet), the maximum predicted acceptable amount of emissions from engines smaller than 250 horsepower (hp) would be 412 lb/hr. 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 one-hour or 8-hour NAAQS; therefore, a registration-specific impacts analysis is not necessary or required.

PM less than or equal to 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 engines or other combustion producing sources. Using the conservative impacts evaluation table at the shortest distance (50 feet) and lowest dispersing stack (feet), for a 250 hp engines, the minimum predicted acceptable amount of emissions would be 0.9 lb/hr for $PM_{2.5}$. 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 was 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.

SO_2 has several state ambient air standards, depending on location. 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 $\mu g/m^3$. The most quantifiable sources of SO_2 at OGS are from flares or other waste stream thermal control devices from burning sour waste streams, or from engines used for compression. Using the conservative impacts evaluation table for flares at the shortest distance (50 feet), lowest dispersing stack height (20 feet), and the new proposed NAAQS (196 μg/m^3), the acceptable amount of SO_2 emissions would be 3.4 lb/hr. For that same 20-foot flare, if it is 1,400 feet away from the nearest property line, the acceptable amount of SO_2 emissions from the table would be 5.4 lb/hr. Other steady state sources of SO_2 include all combustion sources, such as engines. The average OGS has 1250 hp engines and if a typical 18-foot high stack is used, the acceptable amount of SO_2 at 1,400 feet away from the nearest property line would be 47 lb/hr. At 2,700 feet away from the nearest property line, the amount would be 63 lb/hr; and if it is 5,500 feet away from the nearest property line, the amount would be 93.2 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 15 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 sour stream going to an amine reboiler could potentially 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 a small engine with a short eight foot stack, the smallest amount of SO_2 which meets the NAAQS at 50 feet is 2 lb/hr. Based on this information the commission would not expect a demonstration of impacts for any source to be needed at less than 2.0 lb/hr. Based on this information, most sweet sites will meet the new, more stringent NAAQS, regardless of having distances greater than 5,500 feet. For sites with emissions greater than 2 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 5,500 feet from a source. Therefore, applicants should be required to demonstrate impacts of SO_2. Based on this information, sweet sites with great enough SO_2 emission release points and distances to receptors will most likely be able to meet the protectiveness limits of the chart; however, it cannot be concluded that most OGS would not have a problem meeting the protectiveness limits of the chart, especially sour sites. Because of this a protectiveness review is required for SO_2 to demonstrate the site does not have or contribute to an exceedance of any SO_2 NAAQS.

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 the conservative impacts evaluation table for fugitives and vents at the shortest distance (50 feet), lowest dispersing fugitive stack height (3 feet), and the most stringent NAAQS (108 $\mu g/m^3$), the acceptable amount of H_2S emissions would be 0.03 lb/hr. From the same chart, for loading at a 10-foot height, 1,400 feet away from the nearest property line, the acceptable amount of H_2S emissions from the table would be 0.5 lb/hr; for emissions from a tank hatch at 20 feet, with the tank 2,700 feet away from the nearest property line, the acceptable amount would be 1.6 lb/hr. 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, it cannot be concluded that most OGS would not have a problem meeting the protectiveness limits of the chart and a protectiveness review is required for H_2S to demonstrate the site does not have or contribute to an exceedance of any H_2S state ambient air standard.

NO_2 is evaluated using the one-hour NAAQS of 188 $\mu g/m^3$ and the annual NAAQS of 100 $\mu g/m^3$ as measured at the nearest property line to the authorized facilities. A previous compressor station study by the commission showed that the NO_2/ NO_X ratio appeared to max out at around 14 percent in the area downwind of the studied site where maximum NO_X concentrations were expected. Upon review of this information, the commission has determined it is reasonable to allow a lower NO_2/ NO_X ratio than the national default ratio used for air dispersion modeling demonstrations. Given the submitted sampling data and previous commission experience, a ratio of 20 percent is appropriate for 4-stroke engines. Several 2-stroke lean-burn engines in the submitted data set emitted about 50 percent NO_2 and the commission believes the ratio of 50 percent is appropriate for 2-stroke engines. Using a conservative impacts evaluation for engines, the ambient ratio factor of 50 percent of NO_X is NO_2, at the shortest distance (50 feet) and lowest dispersing stack height (8 feet), the maximum predicted acceptable amount of emissions from engines smaller than 250 hp would be 3.9 lb/hr. The ratio of 50 percent is used based on analysis of NO_X to NO_2 in stack sampling discussed later in this document. 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, it cannot be concluded that most OGS would not have a problem meeting the protectiveness limits of the chart and a protectiveness review is required for NO_X to demonstrate impacts of NO_X if greater than 4 lb/hr the site does not have or contribute to an exceedance of any NO_2 NAAQS.

Compliance with ESLs was also evaluated for possible inclusion as a requirement of 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 (hourly 640 $\mu g/m^3$), ethylbenzene (hourly 740 $\mu g/m^3$), xylene (hourly 350 $\mu g/m^3$), other typical chemicals found in petroleum streams (such as propane, butane, n- iso- and cyclo-hexanes, n- iso- and cyclo-pentanes, heptanes, etc). 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.

Forty-four OGS standard permit registrations were evaluated. The commission determined that only benzene requires a protectiveness review in order to demonstrate the site does not have or contribute to an exceedance of an ESL and further the commission believes that this demonstration is adequate to demonstrate protectiveness of total VOCs. The commission received many verbal and written comments that the ESL for condensate and crude oil condensate, and consequently their hourly emission limits, are not representative. The commission has derived the hourly limits from the emission parameters obtained from the oil and gas permit applications, ISC modeling and the agency published ESLs. The commission is open to revising the PBR and standard permit limits if the ESL for condensate and crude oil or any other emission limit changes in any significant manner. Written requests may be sent to Dr. Michael Honeycutt of the Commission's Toxicology Division for re-evaluation of any ESL and the commission will evaluate priorities of the Division for developing ESLs. This ESL evaluation process takes approximately 1 year in accordance with the procedures available at: *http://www.tceq.state.tx.us/implementation/tox/./.*

The current short-term ESL of 3,500 $\mu g/m^3$ was set based on the weight percent of components in typical sweet natural gas condensate. The ESL was developed by calculating each component's weight percent and its respective ESL using a formula for the derivation of a chemical product. Accordingly, an ESL of the typical sweet natural gas condensate can be derived by the following formula where f_n equals the fractional quantity of component 'n' in product X, and ESL_n equals the ESL for component 'n':

Figure 2: 30 TAC Chapter 106 - Preamble

ESL for Chemical Product

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

The components and their weight percent of a typical sweet natural gas condensate are listed as follows.

Figure 3: 30 TAC Chapter 106 - Preamble

Component n	Weight percent
iso-Butane	7--15
n-Butane	15--40
iso-Pentane	10--20
n-Pentane	10--20
n-Hexane	10--20
Heptane	2--10
Octane	1--5

Methylcyclopentane	1--3
Methylcyclohexane	1--3
Benzene	< 1
Toluene	0.1--1.5
Ethylnenzene	< 1
Xylene	1--3

Natural gas condensate typically consists more than 80 percent of C_4-C_8 alkanes which have low acute respiratory effects. High concentrations of these alkanes may cause temporary irritation of the nose and throat and headache, nausea, dizziness, drowsiness, anesthesia, and confusion. The short-term ESLs for alkanes are much higher than those for non-alkanes components, i.e., benzene, ethylbenzene, toluene and xylene (BTEX) in the condensate. The current short-term ESL for natural gas condensate is primarily driven by the BTEX's ESLs. The acute health effects from exposure to natural gas condensate are mainly caused by the impacts of BTEX. If the short-term ESLs for BTEX are met, the short-term impacts for condensate emissions from OGS facilities are expected to be protective. Therefore, there is no need to conduct the short-term ESL review for condensate if BTEX impacts meet their respective ESL. Further review on BTEX is completed later in this document.

The current (interim) short-term ESL (3,500 $\mu g/m^3$) for crude oil was derived based on available occupational exposure limits for similar petroleum hydrocarbons (e.g., gasoline, naphtha, and kerosene) which is conservative. The new short-term ESLs for crude oil and other similar petroleum hydrocarbons, if developed following the 2006 TCEQ Guidelines to Develop ESLs and Reference Values, may be higher approximately by a factor of two to three. Therefore, a higher hourly emission rate for crude oil emissions is expected to be protective.

The commission has determined that process streams that fall in the natural gas category must contain no less than 80 percent methane and ethane. The natural gas ESL was developed with the assumption that the natural gas stream would have no more than 20 percent VOCs. All other process streams should use either condensate or crude oil for estimating overall VOCs, or the specified contaminant as describe in the impacts category.

The determination of specific contaminants which need to be reviewed was based on actual emissions; variability of actual emissions; lowest, highest, and average weight percents of each contaminant; and contribution of each speciated contaminant based on weight percents and ESLs. The following 14 speciated contaminants 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 contaminants with more than four data points (equals a 10 percent statistical cut-off) from the 44 registrations. The chemicals which showed the highest potential culpability for impacts were benzene, toluene, xylene, ethylbenzene, cyclohexane, and methylcyclohexane.

Cyclohexane and methylcyclohexane were evaluated and determined to not be contaminants that drive the need for an impacts review. The commission determined that the conservative modeling results for these contaminants 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 cyclohexane, and methylcyclohexane are not expected to cause an exceedance of ESLs. Three out of 14 data points had represented actual emissions for cyclohexane which were above the 0.32 lb/hr allowable emissions for cyclohexane at 50 feet for fugitive releases; 11 out 14 had represented actual emissions which were less than 50 percent 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.

The magnitude of some of the actual emissions, variability of emissions, and variability of weight percents of xylene, toluene, and ethylbenzene from the 44 registrations, the weighted contributions to impacts, in comparison to allowable emissions based on the impacts tables, required further review by the commission. The represented emissions for 26 of 33 data points were below the allowable emissions of 0.146 lb/hr at 50 feet for toluene fugitives. The 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. Similar results were seen when ethylbenzene was reviewed in typical registrations. Based on this evaluation, impacts evaluations and emission limitations for xylene, toluene, and ethylbenzene were determined to not be necessary for individual registrations.

Benzene was confirmed as the main contaminant of VOC for impacts review. Thirty-four data points were obtained for benzene from the 44 registrations. In particular, the average weight percent was 3, 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 contaminants evaluated. Benzene is considered a relatively toxic air contaminant, and erring on the side of caution, the commission has determined that impacts of benzene must be evaluated for distances to receptors between 50 feet and 5,500 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.

Based on the commission's analysis, only benzene hourly and annual emissions need to demonstrate acceptable impacts when distances to receptors are between 50 feet and 5,500 feet, unless they are below the minimum lb/hr established in the rule. Speciated emissions and total VOCs emissions must be based on site specific or defined representative analysis. Demonstration of meeting the impacts for benzene is a reasonable surrogate for a demonstration for total VOC emission limits in this PBR. The analysis determined that if benzene can meet the impacts analysis and are protective, then all remaining VOCs should meet the impacts analysis and be protective because it has the highest combination of greatest weighted concentration and lowest ESLs of all the VOC contaminants identified for natural gas, condensate, and crude oil.

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) establishes that the reasons for which the commission 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 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 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 prescriptive requirements is burdensome and unnecessary in the commission's opinion. The negligible increases adopted 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 adopted for VOC and NO_X are no greater than 4 percent of the total maximum annual emissions which would be allowed under this section (Level 2 of the PBR). The values for H_2S and benzene are less than 4 percent of the total annual emissions of Level 1 of the PBR. Additional details on the level limits 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 over a rolling 60-month period, and not result in changes at other facilities at the site or increase the OGS potential to emit air contaminants. Keeping records over a rolling 60-month period is the same duration as Title V permit recordkeeping requirements. Title V permit recordkeeping requires the longest or same duration of recordkeeping in comparison to other state of Texas and federal rules. Keeping records over a rolling 60-month period ensures compliance and practical enforceability. Negligible changes still need to comply with technical requirements after recordkeeping is no longer required. Negligible changes are not counted toward registration requirements after recordkeeping is no longer required. Negligible changes must still be incorporated into the next revision or certification of a registration.

Subsection (c)(1)(B)(v) 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 are 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 subsection (c)(2)(A).

Subsection (c)(2) establishes expectations for all authorizations 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 New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), or Maximum Achievable Control Standards (MACT) must meet those requirements, regardless of the requirements of this section. Federal standards applicable to OGS can be found in 40 CFR Parts 60, 61 and 63 (NSPS, NESHAPs, and MACT standards, respectively). Since the OGS PBR was last revised, several federal standards applicable to OGS have been adopted and proposed. The PBR is consistent with the existing federal standards as much as possible. Sources (that is, facilities) subject to MACT standards are classified as either major sources or area sources. Major sources are sources that emit 10 tpy of any of the listed individual hazardous air pollutants (HAP), or 25 tpy of a mixture of HAPs. Area sources of HAPs are not major sources of HAPs. Though emissions from individual area sources are often relatively small, collectively their emissions can be of concern, particularly where large numbers of sources are in heavily populated areas. Most, if not all of, the federal rules that can apply to OGS are discussed briefly below. The brief discussions are not intended to replace familiarity with the federal rules as the EPA has recently been actively changing existing federal rules, proposing new federal rules, and adopting both the changes and new rules, including federal rules that are associated with or can be associated with OGS. Additionally, the EPA is reviewing OGS drilling operations which are beyond the scope of the OGS standard permit and PBR rules. Given the recent scope of changes to and adoptions of NSPS and MACT rules associated with OGS and in general, the commission believes providing detailed descriptions of the federal rules would create confusion in the future between updated and new federal rules in comparison to this background document. Additionally, the commission believes that trying to explain some of the federal rules in more detail would add a level of detail that is beyond the scope of purpose for this background document. Specifically, the existing federal standards are listed:

Oil & Natural Gas Production (MACT HH)

National Emission Standards for Hazardous Air Pollutants for Source Categories from Oil and Natural Gas Production Facilities applies to oil and gas production facilities located at area sources and major sources of HAPs. For major sources of HAPs, the rule applies to glycol dehydration units, tanks with potential for flash emissions, certain fugitive component emission sources at natural gas processing plants, and compressors in volatile hazardous air pollutant service which are located at natural gas processing plants, unless exemptions apply. For area sources of HAPs, the rule applies to triethylene glycol (TEG) dehydration units for which controls are required at certain trigger levels.

Transmission and Storage (MACT HHH)

National Emission Standards for Hazardous Air Pollutants from Natural Gas and Transmission and Storage Facilities applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering pipeline to a local distribution company or to a final end user if no local distribution company, as specified in the rule. For major sources of HAPs, the rule applies to glycol dehydration units, unless exemptions apply. There are no requirements for area sources of HAPs in the rule.

Stationary Reciprocating Internal Combustion Engines (RICE) (MACT ZZZZ)

National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines applies to RICE engines that are located at major sources and area sources of HAPs, unless exemptions apply. A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work energy and which is not mobile.

Petroleum Liquids Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and Prior to May 19, 1978 (NSPS Subpart K

The rule applies to each storage vessel for petroleum liquids which has a storage capacity greater than 40,000 gallons. The rule does not apply to storage vessels for petroleum or condensate located at drilling and production sites prior to custody transfer.

Petroleum Liquids Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978 and Prior to July 24, 1984, (NSPS Ka)

The rule applies to each storage vessel containing petroleum liquids with a storage capacity greater than 40,000 gallons for which construction, reconstruction, or modification commenced after May 18, 1978 and prior to July 24, 1984. The rule does not apply to each storage vessel with a capacity less than 420,000 gallons used for petroleum or condensate prior to custody transfer.

Volatile Organic Liquids Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (NSPS Kb)

The rule applies to each storage vessel containing volatile organic liquids with a storage capacity greater than or equal to 75 cubic meters (approximately 19,800 gallons) for which construction, reconstruction, or modification commenced after July 23, 1984, except that storage vessels are exempt based on capacity and maximum true vapor pressure of the liquid being stored, as specified in the rule. Pressure vessels are exempt, as specified. Storage vessels at specified industry types are exempt. Storage vessels permanently attached to mobile vehicles are exempt, as specified. Each storage vessel with a design capacity less than or equal to 1,589.874 cubic meters (approximately 420,000 gallons) storing petroleum or condensate prior to custody transfer is exempt, as specified.

Stationary Gas Turbines (NSPS GG)

Standards of Performance for Stationary Gas Turbines applies to stationary gas turbines that have a peak load equal to or greater than 10 million Btu/hr based on the lower heating value of the fuel and that commenced construction, modification, or reconstruction after October 3, 1977, except that some turbines may be exempt from some of the rule requirement, as specified. Stationary combustion turbines subject to the requirements of NSPS KKKK (discussed below) are exempt from NSPS GG requirements.

Equipment Leaks of VOC From Onshore Natural Gas Processing Plants (NSPS KKK)

Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants applies to sources at onshore natural gas processing plants that commenced construction, reconstruction, or modification after January 20, 1984, as specified and defined, and to compressor stations, dehydration units, sweetening units, underground storage tanks, field gas gathering systems, and liquefied natural gas units if located at onshore natural gas processing plants. Exceptions for the rule apply as specified. Sources covered by NSPS Subparts VV or GGG are excluded from NSPS KKK.

Onshore Natural Gas Processing SO2 Emissions (NSPS LLL)

Standards of Performance for Onshore Natural Gas Processing; SO_2 Emissions applies to natural gas sweetening units and natural gas sweetening units followed by sulfur recovery units (SRUs) that commenced construction or modification after January 20, 1984. Sites with a design capacity of less than 2 long tons per day of H_2S (as sulfur) have only recordkeeping requirements. Sites that completely re-inject acid gas into oil-or-gas-bearing geologic strata or that do not release acid gas to the atmosphere are not required to comply with the subpart.

Compression ignition (CI) internal combustion engines (ICE) (NSPS IIII)

Standards of Performance for Stationary Compression Ignition Internal Combustion Engines applies to manufacturers, owners, and operators of stationary compression ignition internal combustion engines as specified in the rule. Several applicability dates are listed in the rule and depend on engine size, date of manufacture or remanufacture of the engine, and use of the engine, as specified in the rule. Exemptions apply as specified in the rule.

Stationary spark ignition (SI) internal combustion engines (ICE) (NSPS JJJJ)

Standards of Performance for Stationary Spark Ignition Internal Combustion Engines applies to manufacturers, owners, and operators of stationary spark ignition internal combustion engines as specified in the rule. Several applicability dates are listed in the rule and depend on engine size, engine type, date of manufacture or remanufacture of the engine, and use of the engine, as specified in the rule. Exemptions apply as specified in the rule. In general, the rule is applicable to engines manufactured, modified, or reconstructed after June 12, 2006.

Standards of Performance for Stationary Combustion Turbines (NSPS KKKK)

Standards of Performance for Stationary Combustion Turbines applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu; heat input determination does not including heat recovery or duct burners) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Exemptions apply as specified in the rule.

National Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (MACT YYYY)

National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines applies to existing, new, or reconstructed stationary combustion turbines at major sources of HAPs. Exemptions apply as specified in the rule.

National standards for equipment leaks (MACT H)

National Emissions Standards for Organic Hazardous Air Pollutants for Equipment Leaks applies to pumps, compressors, agitators, pressure relief devices, and other specified equipment that operate in organic service 300 hours or more during a calendar year within sources subject to MACT subparts that reference MACT H. Exemptions apply as specified in the rule.

National standards for separators

National Emission Standards for Oil-Water Separators and Organic-Water Separators applies to oil-water and organic-water separators for which an NSPS or NESHAP subpart or another MACT subpart references MACT VV.

National standards for equipment leaks (NESHAP V)

National Emission Standard for Equipment Leaks applies to pumps, compressors, pressure relief devices, sampling connection systems, and other sources operating in volatile hazardous air pollutant service.

General provisions (MACT A, NESHAP A, and NSPS A)

MACT A, NESHAP A, and NSPS A apply in general. For example, NSPS KKK allows for flares for compliance and references the general control device and work practice requirements for flares under NSPS A, 60.18.

Compliance Assurance Monitoring and Periodic Monitoring

Compliance assurance monitoring (CAM) is a federal monitoring program implemented under the authority of Chapter 122, Subchapter G, to establish minimal monitoring requirements for state and federal rules for emission units (emission units as defined in Chapter 122) that lack sufficient monitoring, testing, and recordkeeping requirements to demonstrate compliance with emission limitations or standards. Since OGS authorized under PBR Level 2 and standard permit can also be applicable to the federal operating permit program, CAM should be considered. Periodic monitoring is a federal monitoring program implemented under the authority of Chapter 122, Subchapter G, and applies to emission units at sites with emission limitations or standards. An emission unit requires periodic monitoring if the emission limitation or standard that the unit is subject to does not specify periodic monitoring (which may consist of recordkeeping) that is sufficient to yield reliable data from a relevant time period that is representative of the emission unit's compliance with the applicable requirement and testing, monitoring, reporting, or recordkeeping sufficient to assure compliance with the applicable requirement. Since OGS authorized under standard permit can also be applicable to the federal operating permit program, periodic monitoring should be considered. Some requirements that could be considered CAM and periodic monitoring requirements were added to the OGS PBR rules. The CAM and periodic monitoring requirements in the OGS rules do not trump more stringent CAM and periodic monitoring requirements under the oil and gas GOPs and in SOPs.

Finally, all facilities and activities must also comply with any applicable state regulation as stated in subsection (c)(2)(C). All facilities and sources in Texas must comply with various requirements in Chapter 101. The commission notes the most common parts of this chapter affecting OGS are Subchapter F, Emissions Events and Scheduled Maintenance, Startup, and Shutdown Activities, and §101.4, Nuisance. Potential nuisance conditions do not only occur with oil and gas from odors or smoke, but in many cases in-plant roads work areas traffic and activities may generate substantial dust problems. Where necessary, operators are reminded that sufficient care and controls must be taken with all material handling and traffic which may cause dust so as to not cause a nuisance.

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

All OGS, especially sour sites, must ensure compliance with the ambient air standards in Chapter 112. The property-line determinations must show compliance with SO_2 property-line standards ranging from 715 $\mu g/m^3$ to 1021 $\mu g/m^3$ (0.28 ppmv in Galveston or Harris Counties, 0.32 ppmv in Jefferson or Orange Counties, and 0.4 ppmv for the remainder of the state) and H_2S standards range from 108 $\mu g/m^3$ to 162 $\mu g/m^3$ (depending on impacts occurring at residences, businesses, or on commercial property). These standards were evaluated and this proposal relies on using the most stringent of standards so that a simplified set of acceptable emission tables could be developed. Sulfur recovery under Chapter 112 is not addressed here as no SRUs will be allowed under the standard permit.

In addition, sites in nonattainment and near nonattainment counties must comply with various standards in 30 TAC Chapter 115, Control of Air Pollution from Volatile Organic Compounds, for VOCs and 30 TAC Chapter 117, Control of Air Pollution from Nitrogen Compounds, for NO_X. The affected areas include the following: Houston/Galveston/Brazoria (HGB) - Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller Counties; Dallas/Ft. Worth (DFW) - Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties; Beaumont/Port Arthur (BPA) - Hardin, Jefferson, and Orange Counties; and East Texas counties (ETC) - Anderson, Brazos, Burleson, Camp, Cass, Cherokee, Franklin, Freestone, Gregg, Grimes, Harrison, Henderson, Hill, Hopkins, Hunt, Lee, Leon, Limestone, Madison, Marion, Morris, Nacogdoches, Navarro, Panola, Rains, Robertson, Rusk, Shelby, Titus, Upshur, Van Zandt, and Wood Counties. The requirements in Chapter 115 include: Subchapter B, Divisions 1 and 2, Storage of Volatile Organic Compounds and Vent Gas Control, respectively; Subchapter C, Division 1, Loading and Unloading of Volatile Organic Compounds; Subchapter C, Division 3, Control of Volatile Organic Compound Leaks from Transport Vessels; and

Subchapter D, Divisions 2 and 3, concerning fugitive emission control in natural gas/gasoline processing operations. Depending on the vapor pressure at which certain liquids are stored or transferred, and the quantity of liquids being processed, for both crude and condensate, different control devices are required to reduce or eliminate air contaminants. Further, the site's location will require more stringent controls if located in serious or severe nonattainment areas. Like other state regulations, there are exemptions depending on specific operations at a given site.

Those OGS which have combustion devices and are located in nonattainment and near nonattainment counties must comply with requirements in Chapter117. For stationary, reciprocating internal combustion engines, NO_X emission limits for specified areas vary and depend on several criteria: the type of fuel being used, the hp of the engine, and the date of modification (modification of an existing facility as defined under §116.10), reconstruction, or relocation. The compliance date, which determines when a given engine is subject, will also vary. Additionally, there are different NO_X emissions limits based on whether a site is considered major or minor. Again, there are exceptions for when engines in a specified area are exempted from the provisions of Chapter 117. There are also Chapter 117 restrictions that apply to water heaters, small boilers, and process heaters, which are covered under Subchapter E, Multi-Region Combustion Control, Division 3. There are applicable dates and operating parameters which will cause certain equipment to become applicable to these provisions, including but not limited to maximum Btu capacity, manufacture date, and heat output. Under Subchapter E, Division 1, electric generating units are subject to limitations based on installation date, use for compensation, use in turbine exhaust ducts, and area of location. Each provision under Chapter 117 will require different methods of reporting and recordkeeping as well and will vary depending on location and the subchapter under which a company or facility is subject.

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 commission may deny 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. In this subsection, the reasons the commission may deny a PBR include: failing to meet the requirements of the PBR; misrepresenting or failing to disclose fully all relevant facts in obtaining the permit; or being indebted to the state for fees, payment of penalties, or taxes imposed by the statutes or rules within the commission's jurisdiction. Furthermore, a denial under this section constitutes a final commission action

Subsection (c)(4) has been added in response to comments that the commission should develop an authorization under this section for facilities which result in neglibigble emissions and therefore should not be required to comply with the complexity of the section's new requirements. Using the impacts evaluation at very conservative values (50-inch distance), typical small well-head operations, facilities, and materials, the commission has defined a subset of facilities which only need to be kept in good working order in order to minimize emissions, and otherwise should not require more extensive requirements, registration, records, or monitoring.

To ensure that only t he smallest group of facilities and associated emissions are excluded from the notification, registration, emission calculation, impacts analysis and other requirements of the PBR, the commission has limited the scope of subsection (c)(4)(A) to all dependent facilities in 1/4 mile of a project. This is also consistent with the applicability requirements throughout this section and the standard permit.

The agency has determined that at a particular level of production some facilities may be of such insignificant emissions levels that requiring notification or registration is overly burdensome. This evaluation includes (but not limited to) stripper wells producing up to 10 barrels of oil equivalent per day or natural gas up to 60,000 cfd. At many of these locations, small engines are used for a variety of purposes. The commission determined engines with a site hp rating less than 450 hp and operating on sweet natural gas would not exceed the NO_2 allowable impact using the most restrictive value in the commission modeling tables. Further, engines with a site hp rating of less than 100 hp and operating on sour gas containing no more than 10,000 parts per million weight (ppmw) H_2S would not exceed the allowable SO_2 impact using the most restrictive value in commission's modeling tables. Engines with a site hp rating of less than 20 hp and operating on sour gas containing greater than 10,000 ppmw H_2S but no more than 50,000 ppmw H_2S would not exceed the allowable SO_2 impact using the most restrictive value in the commission's modeling tables.

With input from industry, the agency was able to establish that the smallest facilities associated with oil and gas production are typically wellheads, pump-jacks, Christmas trees, and metering stations. Emissions associated with the smallest of these facilities are mainly from fugitive components, while larger facilities can have additional sources such as separators and tanks. For the purpose of this evaluation separator natural gas and liquids were assumed to be routed to an available sales pipeline. Furthermore, the agency assumed the smallest facilities included a maximum of four pump seals and four open-ended lines. These assumptions were based on staff experience and industry support. The agency took the approach of determining the typical component and facility count at which these small facilities may operate and remain under the exclusion level.

In order to determine the number of components at which the *de minimis* level could be established at a site handling natural gas only (with no liquid separation or storage) with fugitive components (in gas service) being the only significant source of VOC, the data collected was compared against the impact tables referenced within the oil and gas package associated with natural gas emissions. This natural gas table shows protective emission rates for condensate/crude oil based on the short term ESL of 18,000 $\mu g/m^3$. Additionally, for the purpose of this evaluation, the agency used the fugitive adjustment factors established by the agencies air-modeling department. Therefore, the emission rate determined to be protective for fugitive components at a 3-foot stack height and 50-foot distance to receptor was 1.33 lb VOC/hr. As a result, a small facility could have any combination of valves, flanges, and connectors or meter runs totaling 720 components. Note that this fugitive emission calculation is based on an assumed 97 percent VOC content in the gas.

The method used to determine the *de minimis* level for the larger small sites is similar as the method used above, with the difference being that the significant sources of VOC at these sites are produced water tanks and loading and fugitive components. The amount of fugitive components able to be at a site and still be protective now must be less than the case above where fugitive emissions were the only significant source of VOC emissions and the site was limited to less than 1.33 lb VOC/hr to be protective at a 50-foot distance from facility to receptor. It was decided that five pump seals and five open-ended lines and any combination of valves, flanges, and connectors or meter runs totaling 150 components was appropriate, which corresponds to about 1.02 lb VOC/hr. Since 1.02 is less than the 1.33 lb VOC/hr, it allows other VOC emission sources to be present at the site. Note that this fugitive emission calculation is based on an assumed 97 percent VOC content in the liquid.

Loading hourly emissions were estimated with the AP-42 loading equation using typical condensate properties from AP-42 (Reid vapor pressure (RVP) 7 (gasoline) with 1.45 splash loading saturation factor, 4.3 psia true vapor pressure, 68 lb/lbmol molecular weight, liquid temperature of 70 degrees Fahrenheit, and hourly loading rate of 8,000 gallons/hour). It should be noted that splash loading was assumed as it is has been the agency's experience that industry practice is to use either vaccum trucks or pump trucks with splash loading. From this calculation and the assumption that 1 percent of the emissions are VOC from produced water, the hourly loading emission rate is 0.80 lb VOC/hr.

Using the weighted ratio method, it was determined that tank emissions of 15.56 lb VOC/hr is protective with 1.02 lb VOC/hr fugitive emissions and 0.80 lb VOC/hr loading emissions. A similar approach was also taken to look at H_2S and benzene emissions using the protectiveness values based on the 1-hr state ambient air quality standard of 108 $\mu g/m^3$ for H_2S and the short term ESL of 170 $\mu g/m^3$ for benzene. Using this 15.56 lb VOC/hr protective tank emission rate and other information, the agency developed a volumetric flow rate of produced water (1,205 barrels produced water per day) that corresponds to a site that has protective emissions at the shortest distance to receptor of 50 feet. How this flow rate was developed is described here. The agency obtained information on worst case conditions for stripper wells from industry. The conditions are: 1) 150-200 psig separator pressure, 2) 100-120 degrees Fahrenheit separator temperature, 3) 14.7 ambient pressure, 4) 90-95 degrees Fahrenheit ambient temperature, 5) 10 barrels per day crude oil production rate, 6) 50-60 API gravity for condensate, 7) 25-38 API gravity for crude oil, 8) relatively high RVP for condensate, and 9) lower RVP for crude oil. Since sample data could not be found with all the criteria above satisfied, the approach taken was to review a variety of condensate and crude oil samples and use E&P Tanks to estimate tank flash, working, and breathing emissions. The samples were from the E&P Geographical Database, permitting applications, and industry supplied data. The cases reviewed for condensate were cases found to be representative of condensate liquid with high VOC content based on API gravity being above 50 - Southeast Region 23 (SE23), SE24, Southwest Region 22-33, (SW22-33). There were no condensate cases found with any H_2S content. The cases reviewed for crude oil were cases found to be representative of crude oil with lower API gravity and RVP - three permit application submittals for typical condensate, one industry submittal of typical Permian Basin data, SW1, SW3, SW6-8, and SW10. It should be noted that all of the crude oil cases had H_2S present ranging from 0.01-3.82 mol percent.

The program was run using the separator pressure and temperatures, and material characteristics (composition, C10+ characteristics, API gravity, RVP) from the actual sampled data. Each run was done with an ambient pressure and temperature of 14.7 psia and 95 degrees Fahrenheit, respectively. Produced water emissions were calculated as 1 percent of either the crude or condensate emissions. The ratio of the emissions (VOC, H_2S, and benzene) to the volumetric flow rate was calculated for each case so that each case could be compared. This ratio was then used with the rate of emissions (VOC, H_2S, and benzene) determined to be protective for produced water tanks from the modeling/impacts tables to calculate the volumetric flow rates that correspond to protective emission rates. The minimum flow rate found to correspond to a protective emission rate of VOC, H_2S, and benzene, with VOC liming the number, is 1,205 barrels produced water per day.

The commission expects that as new wells age and production declines that groups of facilities registered under Level 1 or Level 2 of this section will move into this category and ultimately void their registrations if no future expansion is feasible at that time.

Subsection (d) establishes which facilities are authorized under this section. 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 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, H_2S scavenger chemical reaction vessels for sulfur removal, 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; surface support facilities associated with underground storage of gas or liquids; 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 startup startups and shutdowns (except for planned MSS degassing operations).

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 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 applicability 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 as referenced in subsection (c)(2)(A). The only way to prevent triggering federal PSD requirements is to maintain a second SRU to switch over during maintenance operations. Since the review of permitted OGS did not reveal any dual SRUs, the commission concluded 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 subsection (d)(2)(B), CO_2 hot carbonate processing units were excluded since the commission 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 commission was not able to evaluate these units. The commission requested comments on CO_2 hot carbonate processing units, but received no information from commenters and therefore adopts subsection (d)(2)(B) to exclude these units.

The commission adopts 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 commission'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. 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. In 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. 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. In response to comments, subsection (d)(2)(H), which was proposed to prohibit the use of the PBR in an Air Pollutant Watch List (APWL) area for any applicable APWL contaminants for that area, has been deleted. The commission agrees that isolating the oil and gas industry is inappropriate at this time and the need to more strictly control air pollutants in these areas justifies changes to the general requirements for all PBRs. The current practice to closely evaluate any increases of pollutants of concern in AWPL designated areas will continue, and continuing to pursue this policy and practice will help ensure that PBR authorizations will not contribute to existing, monitored problems in specified areas of the state.

The commission adopts a requirement that 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 OGS under the PBR rule is subject to Best Management Practices (BMPs) requirements. The commission adopts subsection (e) to require BMPs and minimum requirements for new and changed facilities at an OGS authorized under this 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, the commission adopts subsection (e)(1) to reiterate 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. Additionally, the commission adopts subsection (e)(1) to require sites to establish a program for replacements, repairs, and maintenance on facilities for those chosen by the operator to meet the limitation of this section. The commission adopts subsection (e)(1)(A) for addressing compliance with manufacturer's specification and recommended programs applicable to equipment performance and effect on emissions as listed in subsection (e)(1)(A) has been added to ensure that equipment is operated as intended. The commission adopts subsection (e)(1)(A) as initially proposed and adds the words *compliance with* at the beginning of subsection (e)(1)(A) to provide clarity of meaning in response to comments. The commission adopts cleaning and routine inspection in subsection (e)(1)(B) to ensure ensures that equipment is not left to operate endlessly without necessary routine attention. However, cleaning does not include degassing, which is separately addressed in the rule. The commission adopts subsection (e)(1)(B) as initially proposed and adds the word routine in front of inspection for clarity. The commission adopts subsection (e)(1)(C) to provide for replacement and repair of equipment on schedules which prevent equipment failures and maintain performance as listed in subsection (e)(1)(C). This is to ensure that when replacement and repair of equipment is necessary, it is done at an interval both consistent with manufacturer's recommendations and at a time of the operators choosing. The commission has determined that replacements, repairs, and maintenance of equipment are good engineering practice and necessary to ensure minimization of emission releases.

The commission deletes the initially proposed language is subsection (e)(2) and instead moves the initially proposed language from subsection (e)(3) to subsection (e)(2). The commission adopts subsection (e)(2) that requires OGS facilities to be operated at least 50 feet from any property line or receptor (whichever is closer to the facility). Fifty feet 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. Furthermore, the commission adopts subsection (e)(3)(A) as initially proposed and changes subsection (e)(3)(A) to subsection (e)(2)(A). Subsection (e)(2)(A) requires that any valve that is for isolation and for safety purposes can only consist of fugitive components, and must meet the separation requirements of at least 1/2 the distance of any applicable easement as defined by federal requirements (49 CFR Part 195.210 and 195.248), guidance set forth by the Texas Railroad Commission, or local entities. The commission adopts subsection (e)(2)(B) to exempt from the 50 feet distance requirement any properly authorized existing facility, even if modified. The commission adopts subsection (e)(2)(C) to waive the distance limitation for existing OGS facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50-foot requirement. Replacement facilities must meet all other requirements of this section. The language under subsection (e)(2)(C) is essentially as previously proposed with different wording used in response to comments to provide more clarity. In response to comments, the commission added language to subsection (e)(2)(C) to encourage moving facilities to meet the 50-foot requirement. In response to comments, the commission added language to subsection (e)(2)(C) to indicate replacement facilities must meet all other requirements of the OGS PBR; the commission does not consider replacement of facilities as maintenance as was claimed in comments. The commission determines that replacement facilities are new facilities. Existing OGS facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized would be exempt from this distance limitation even if they are modified, unless good engineering practice would permit, since it is unfeasible to move these facilities. The commission has also clarified that this distance is not applicable if a receptor is subsequently built within this buffer zone.

The commission adopts subsection (e)(4) to provide for BMPs and minimum requirements for engines and turbines. The commission moves subsection (e)(4) to subsection (e)(3).The commission determines that, although not specifically stated in the OGS PBR rule, to eliminate confusion over when an OGS must register or notify the commission for engines and turbines and to account for engine and turbine rules and requirements that are not accounted for in §106.512, the OGS PBR rule language does not allow the previous out-dated requirement of

§106.512 to be used. The commission determines that instead, new or modified engines and turbines under the OGS PBR must meet specific NO_X, VOC and CO requirements. These requirements criteria are based on Tier I BACT determinations, current Chapter 117 requirements and federal 40 CFR Part 60 NSPS. The commission determines that some existing engines must meet specific NO_X requirements by specified phase-in dates. The commission adopts subsection (e)(4)(A) to require engines and turbines to meet the emission and performance standards listed in Table 9 in subsection (l). The commission moves this language to subsection (e)(3) to require engines and turbines to meet the emission and performance standards. The commission changes Table 9 to Table 6 and changes subsection (l) to subsection (m).The commission adopts in subsection (m), Table 6, "Engine and Turbine Emission Operational Standards" due to renumbering and to place the table next to the engine modeling table. In response to comments, the commission adopts a fourth engine type, dual-fuel, and requires that it meet the standards for 4-stroke lean-burn engines because of the similarity in operation and control options for both types of engines. Also the commission adopts a clarification that the rich and lean-burn engine standards apply to only non-emergency, spark-ignited rich and lean-burn engines. The manufacture date is the date of original manufacture unless reconstructed as defined by 40 CFR Part 60 NSPS regulations in which case the reconstruction date becomes the manufacture date. 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 adopting 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 40 CFR Part 60 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. 2-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(m), Table 6 applies standards to rich-burn engines greater than 100 hp, and lean-burn engines greater than 500 hp, and lean-burn engines less than or equal to 500 hp manufactured on or after July 1, 2008. The commission proposed rich-burn engine standards that apply to engines greater than 100 hp. In response to comments, the commission adopts standards that apply to rich-burn engines greater than 500 hp. After reviewing cost data provided by several commenters, the commission believes that the majority of engines under 500 hp will be replaced with newer engines that meet or exceed the standards in subsection (m), Table 6 within a reasonable amount of time. The commission does not believe the additional expense is appropriate given the remaining useful life of those engines. Rich-burn engines greater than 500 hp have until 2020 to modify existing catalyst trains if necessary to meet this rule. This is the only additional control cost that has been imposed on the industry for rich or lean-burn engines in this rule. Costs are expected to be minimal due to the schedule in subsection (m), Table 6 which allows current maintenance plans to incorporate the potential need for enhanced control. In response to one comment, the commission adopts a clarification that the standard for rich-burn engines manufactured after January 1, 2011 applies to engines manufactured on or after the date. 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. The commission adopts a VOC standard for rich-burn engines greater than 100 hp and manufactured before January 1, 2011. In response to comments, the commission adopts no VOC standard for these engines. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at sites with larger potential to emit is appropriate. The additional cost of monitoring for VOC has been eliminated but registrations still must contain appropriate estimates of emissions. The commission proposed subsection (e)(4)(B) for documenting an engine's manufacturer date and type, hp rating, and any previous emissions results summaries in a registration. This language has been deleted from the adopted rule. This issue is addressed further in the response to comments.

The commission adopts subsection (e)(3)(A) (proposed as subsection (e)(4)(C)) for limiting fuel for engines. 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 Table 6 in subsection (m) and follow the BMP, they are authorized under the PBR. The commission adopts subsection (e)(3)(A) (proposed as (e)(4)(C)) to provide diesel fueled engines used for back-up power generation and periodic power needs at OGS if the fuel has no more than 0.05 percent sulfur and is operated less than 876 hours per rolling 12-month period. The commission deletes the sweet gas or liquids language from subsection (e)(4)(C) in response to comments. The commission determines that limiting use to sweet gas or liquids is unnecessary and arbitrary limit and that it is not in the best interest of OGS to use sour gas or liquids that would damage combustion units. The commission adopts subsection (e)(4)(C) to provide for the use of liquid fueled engines for back-up power generation and periodic power needs. The commission changes subsection (e)(4)(C) to subsection (e)(3)(A). The commission adopts the sulfur content and operating time restrictions as initially proposed. In response to comments, the commission changes diesel fueled to liquid fueled. The commission determines that limiting the liquid fuel type to only diesel is an unnecessary and arbitrary limit. The commission adopts subsection (e)(3)(B) to allow the use of engines and turbines for more than 876 hours per rolling 12-month period for electric generation if no electric grid access is available and if the turbines and engines meet Table 9 (changed to Table 6 in subsection (m)) standards for engines and turbines, or else, electric generators must meet only the technical requirements of the Air Quality Standard Permit for Electric Generating Units. The commission changes the language in subsection (e)(3)(B) from no electric grid access to no reliable electric grid access in response to comments. The commission agrees that an available electric grid may not be able to handle the additional electricity load for OGS without significant upgrading of the electric grid itself. The commission added language to clearly indicate that the emissions from EGUs need to be included under OGS registration (not the EGU standard permit.) The commission moves subsection (e)(4)(D) to subsection (e)(3)(B). Finally, the commission adopts subsection(e)(3)(C) – (D) (proposed as (e)(4)(E) and (F)) to require that engines and turbines meet all the requirements of 30 TAC Chapter 117 and all applicable requirements of relevant 40 CFR Part 60 NSPS and 40 CFR Part 63 MACT standards, respectively. This subsection requires operators to follow the more stringent or additional requirements, regardless of this section. These requirements include 30 TAC Chapter 117 and various 40 CFR Part 60 NSPS and 40 CFR Part 63 MACT standards (additional details can be found in the Air Quality Standard Permit for Oil and Gas Sites technical summary). The commission adopts subsection (e)(4)(E) to (F) as initially proposed. The commission moves subsection (e)(4)(E) and(F) to subsection (e)(3)(C) and (D), respectively and adopts as initially proposed. The commission also adds and adopts subsection (e)(3)(E) to provide for allowing compression ignition engines rated less than 225 kW (300 hp) provided that emissions are less than or equal to the emission tier for an equivalent sized model year 2008 non-road compression ignition engine under 40 CFR §89.112, Table 1. The commission determines that, in general, the use of such compression ignition engines is acceptable at OGS.

Additionally, the commission notes in only the preamble that the PBR does not authorize engines used for drilling purposes. The commission does not have regulatory authority over drilling operations. Additionally, in almost every instance, engines used for drilling purposes 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 commission determinations.

The commission proposed subsection (e)(5) but renumbers and adopts subsection (e)(4) and adopts requirements 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, as so often represented by industry, the agency believes that the amount of VOCs and H_2S emissions from these sources the agency believes can still actually be substantial. This is due to the open-topped tank or pond being exposed to the evaporative effects of the sun and wind. Therefore, the commission determines that VOCs or H_2S emissions from open-topped tanks or ponds are allowed up to a potential to emit equal to 1.0 tpy of VOC or 0.1 tpy of H_2S. The commission adopts subsection (e)(5) as initially proposed. The commission moves subsection (e)(5) to subsection (e)(4).

The commission adopts BMP to ensure that all fugitive components, including those from enclosed tanks, are kept in good working condition and are not found to be leaking liquids or gases. It is reasonable to assume that companies will not want to lose substantial amounts of product. As such, all components shall be physically inspected quarterly for leaks. This is to ensure that any gross leaks are immediately addressed. Additionally, all seals and gaskets in

VOC or H_2S service shall be installed, checked, and properly maintained in order to prevent leaking. The commission adopts subsections (e)(5) and (e)(6) to address BMPs requirements for fugitives. The commission adopts requirements for fugitives with significant deletions, re-writes, movement, and re-arrangement in comparison to previously submitted subsection (e)(6) and (7). The commission addresses only some of the details of what was proposed for fugitives in comparison to what the commission adopts for fugitives. The commission lists for reference additional details about what was proposed for fugitives in following paragraphs. The commission adopts subsection (e)(6) to provide for the applicability of BMPs to fugitives. The commission adopts subsection (e)(6) and in response to comments adds language to clarify that this provision is applicable to all fugitive components associated with a project. The commission moves subsection (e)(6) to subsection (e)(5). The commission proposes subsection (e)(6)(A) for requirements for open ended valves and lines. In response to comments, the commission adopts for subsection (e)(5)(A) language that requires fugitive components to be physically inspected for leaks on a quarterly basis. The commission determines in response to comments that the initially proposed monitoring requirements for fugitive components were too stringent for fugitive components under the OGS PBR. Therefore, the commission revised what is required for fugitive monitoring under the OGS PBR. Additionally, the commission also adopts flexibility for additional monitoring as explained below.

The commission intentionally avoids the use of audio, visual, and olfactory (AVO) in subsection (e)(5)(A) as AVO is actually Leak Detection and Repair (LDAR). Subsection (e)(5)(A) is not LDAR. Additionally, the commission believes it is reasonable to assume that OGS will not want to lose substantial amounts of product. As such, the commission determines that all fugitive components need to be physically inspected quarterly for leaks. The commission moves subsection (e)(6)(A) to subsection (e)(5)(A). The commission adopts subsection (e)(5)(B) to require that all seals and gaskets in VOC or H_2S service be installed, checked, and properly maintained in order to prevent leaking. The commission deletes the language in subsection (e)(6)(B), as the language the commission adopts in subsection (e)(5)(A) addresses inspection requirements for all fugitive components and installation and maintenance requirements for all fugitive components are addressed in other language that the commission adopts in the OGS PBR. Additionally, the commission determines that the initially proposed language is too vague. In response to comments, the commission adopts detailed language in subsection (e)(6)(B) to require that all fugitive components found leaking be repaired except when the repair would create more emissions than the repair would make during planned shutdowns; this is to ensure that any repair operations are not actually do more harm than good in increase site emissions levels. The commission determines in response to comments that the initially proposed repair requirements for fugitive components were too stringent for fugitive components under the OGS PBR. Therefore, the commission reevaluates what is required for repair of leaking fugitive components under the OGS PBR. Additionally, the commission also adopts flexibility for additional options as explained below. Again, the commission intentionally avoids the use of AVO as AVO is actually LDAR. The commission moves subsection (e)(6)(B) to subsection (e)(5)(B). For components found to be leaking every reasonable effort must be made to repair leaking components immediately. The commission adopts subsection (e)(5)(C) to require that tank hatches that are not designed to be completely sealed need to stay closed (but not completely sealed in order to maintain safe design functionality) except for sampling or planned maintenance activities. Additionally, in response to comments, the commission adds to subsection (e)(5)(C) gauging, loading, and unloading to the list of exceptions for when tank hatches do not need to be closed. The commission agrees open hatches can be necessary for safe loading and unloading of tanks. The commission agrees that open hatches can be a necessity for gauging of tank levels. The commission requires tank hatches to be gasketed and to 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. For components found to be leaking every reasonable effort must be made to repair leaking components immediately. However, for instances where repair of a component would require a unit shutdown, which would create more emissions, the repair may be delayed until the next shutdown. This is to ensure that any repair operations are not actually do more harm than good in increase site emissions levels. Except for periods when sampling, gauging, loading, unloading, or maintenance is required, 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, the commission determines that 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 is 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 adds and adopts subsection (e)(5)(D) to require new and reworked valves and piping connections to be located in a place that is reasonably accessible for leak checking to the extent good engineering practices will permit and to require that underground process pipelines have no buried valves that cause fugitive monitoring to be impractical. Reasonably accessible fugitive components and not burying valves is good engineering practice and is necessary to ensure that leaking components can actually be fixed if found.

The commission adopts subsection (e)(6) for establishing an option for new and replaced fugitive components and instrumentation in gas or liquid service to comply with a fugitive monitoring program. The commission adopts language in subsection (e)(6) to allow LDAR fugitive monitoring as an option in lieu of otherwise required fugitive monitoring, and the language indicates that Table 6 of subsection (m) requirements are applicable if LDAR is chosen. The commission adopts language in subsection (e)(6) requiring that all fugitive components be inspected on a weekly basis if LDAR is chosen as an option. The commission determines in response to comments that the initially proposed monitoring requirements for fugitive components were too stringent for fugitive components under the OGS PBR. Therefore, the commission re-evaluates what is required for fugitive monitoring under the OGS PBR. The commission adds LDAR fugitive monitoring as an option, not a requirement, under the OGS PBR. Again, the commission intentionally avoids the use of AVO in subsection (e)(6). The commission determines that weekly physical inspections are necessary to add additional assurance that OGS meets claimed control efficiencies under LDAR. The commission believes that significant leaks are likely to be found more quickly during weekly physical inspections in comparison to only quarterly physical inspections. Additionally, the commission allows for claiming a control efficiency of 30 percent for components that have no LDAR control efficiencies by using weekly physical inspections.

The commission adopts subsection (e)(7) to allow industry the option to claim control efficiencies for all tanks, process vessels, and temporary liquid storage tanks containing VOC and H_2S if necessary to meet emissions impacts. This control efficiency is based on an operational design requirement for a tank painting of a color that minimizes the effects of solar heating. This paint color shall have a solar absorbance factor of 0.43 or less as referenced in Table 7.1-6 of AP-42. Furthermore, the painting of tank surfaces should not only comply with the paint producers recommended application requirements if provided but also in sufficient quantity as to be considered solar resistant and thereby of good condition. For tanks not painted to either paint producers recommended application requirements or sufficient quantity as to be considered solar resistant the commission will consider the tank conditions to be of poor quality and therefore less solar resistant regardless of color. While the argument can be made that rust falls within the approved solar absorbance factor range, for these purposes rust does not constitute a paint color but rather a condition of tank integrity. Therefore, tanks with rust are expressly excluded from the approved solar absorbency colors list provided from AP-42.

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 percent 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 Section's 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 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 percent 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. Additionally, minimal amounts of rust may be present not to exceed 10 percent of the external surface area of the roof or walls of the tank and in no way may compromise the integrity of the tank. Lastly, for tanks or vessels in an area whereby a local, state, federal law, ordinance, or private contract predating this section's effective date, established in writing, allows tank and vessel colors other than white, these requirements do not apply.

The commission has reviewed storage tanks used for crude oil, condensate, produced water, pressure tanks with liquid petroleum liquids, fuels, treatment chemicals, and slop and sump oils. The commission is not limiting the applicability of these requirements to any one type of tank for OGS (pressure tank, fixed roof, IFR, or EFR tanks). By far the most common tank at production PBR OGS are the 200- to 400- barrel fixed roof tanks. These tanks are below the storage capacity triggering 40 CFR Part 60 NSPS Subpart Kb standards and are small enough to be picked up and moved by truck. Tank working and breathing emissions can be estimated using the TCEQ Chemical Section's Storage Tank Guidance for short-term and annual emissions. Flash emissions can be estimated in accordance with September 30, 2009: Guidance

- Calculating VOC Flash Emissions from Crude Oil and Condensate Tanks at Oil and Gas Production Sites available at: *http://www.tceq.state.tx.us/permitting/air/announcements/nsr_announce_9_30_09.html.* However, please be aware that the commission is ever improving the method in which emissions from tanks may be evaluated and that new guidance may become available in the future.

The commission adopts subsection (e)(8) to allow glycol dehydration systems to claim the control efficiencies provided in the GRI-GlyCalc Glycol Dehydrator Emission Estimator program under the following provisions. When the GRI-GlyCalc program is used to estimate emissions from a glycol dehydrator, then the unit emission points must be monitored and recorded. Additionally, in order for the GRI-GlyCalc program to be accepted protocols establishing the use of the program will be provided by the TCEQ. This is to ensure that the program is used in the most standardized way possible. The dehydrators are a common facility at OGS and have the potential for high hourly emissions including benzene, toluene, ethylbenzene, and xylenes (BTEX). With an efficient condenser design the water and organic vapors can be condensed and captured. The commission knows they can often be ineffective due to non-saturated vapor conditions; varying coolant temperature and carry out due to high vapor velocity; or ineffective droplet capture. After careful evaluation of the GRI-GlyCalc program the agency feels comfortable accepting control efficiencies claimed by the program as long as unit monitoring is provided. These unit record keeping requirements listed in subsection (m), Table 8 include; weekly dry gas flow rate, adsorber pressure and temperature, glycol type, and circulation rate. Each of these record keeping requirements should be a part of routine operational monitoring requirements in order to ensure proper operation of the glycol dehydration unit as well as to ensure pipeline quality standards are adhered too. For these reasons, the agency feels unit monitoring and record keeping does not go above what is required for normal routine glycol dehydrator operations. Additionally, where control of flash tank or reboiler emissions are required to meet subsection (k) of this section, the following control monitoring and record keeping requirements apply weekly: flash tank temperature and pressure, any reboiler stripping gas flow rate, and condenser outlet temperature. The agency feels that these control monitoring and record keeping requirements are necessary in order to ensure controls are adjusted and working properly to achieve claimed control status and efficiency. Controls such as a VRU, flare, or thermal oxidizer must comply with their respective monitoring and recordkeeping requirements and can only claim their respective efficiency. Reboiler firebox control efficiency may be claimed up to 99 percent as long as records indicating continuous operation are provided. It is expected that any claimed control devices used in conjunction with the glycol dehydrator be operating in unison. This is to ensure that for periods when emissions are being released from the glycol dehydrator these emissions are recovered or destroyed properly. Lastly, the commission understands that due to the remote nature of some OGS weekly monitoring and record keeping requirements may seem burdensome. However, the commission feels that maintaining pipeline quality product is of utmost importance. Hence, weekly status checks of site operations are necessary.

The commission has also clarified in subsection (e)(8) that other appropriate emission estimation methods must be used consistent with state and federal regulations and protocols.

The commission adopts (e)(9) 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 percent or 99 percent 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 percent destruction claim with basic monitoring. Additional confidence is based on the applicant's dependence on the efficient function of the reboiler or heater to run the process properly. There is less confidence where the waste gas enters the fire box separately or with the combustion air. However, streams commonly burned in this fashion can be very combustible so a claim of up to 90 percent destruction can be made with basic monitoring. Obviously streams with high concentrations of CO_2 or nitrogen would garner concern in how effectively the combustible contaminants can mix and burn, but where long residence times and high temperatures are reached, destruction can be much better than 90 percent and the commission allows up to 99 percent 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 control for reboilers/heaters is the use of a flash tank on glycol dehydrators and some amine units, 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. 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 an equivalent monitoring process. 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 run time 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 the entire waste gas stream was directed to a fully effective control for run time claims beyond 50 percent.

Two common control systems used at OGS are vapor recovery systems (VRS) and thermal destruction units. VRSs can cover different types of recovery systems, both by mechanical and chemical means. In subsection (e)(10) the commission establishes the expectations for VRSs. Systems (VRSs are designed to capture vapors from process vessels such as oil/condensate tanks and produced water tanks. VRSs can cover different types of recovery systems, both by mechanical and chemical means. The most common type seen at OGS are the mechanical type, which use a compressor to collect the vapors and route them to a condenser, where the liquids are sent back to the tank and the gases to the sales pipeline. The other type is a liquid system, where the vapors are routed through a liquid and they are absorbed into the liquid. These systems are also vapor recovery systems because the vapor that has been absorbed can be recovered for profit. The VRSs that use mechanical means will be referred to as mVRUs and those that use chemical means will be referred to as lVRUs.

In a typical design for mVRUs, one or more tanks are manifolded to a common suction line and piped to the suction scrubber on the mVRU. An independent sensing line is run from the most active or farthest tank to the sensing unit on the mVRU. The discharge piping from the mVRU is connected to the gas gathering line, a meter run, or the suction of the field gas compressor. Condensates that fall out in the suction scrubber are generally piped back to a stock tank.

Typically, mVRUs are configured to stop and start automatically, depending on the pressure in the tanks. An efficiently designed mVRU must incorporate a bypass system that will initiate automatically and divert the discharge volume back to the suction scrubber. This process allows tank pressure to build back to the point at which collection occurs. If the pressure continues to decrease while in the bypass mode, the unit will shut down and wait in standby for the start pressure to be obtained. Additionally, mVRUs should be configured to shut down before any type of vacuum is reached to avoid pulling oxygen into the tanks or imploding them. If oxygen does get pulled into the system, it is typically caused by an improperly designed package, improperly sealed tank hatches, or leaking relief valves. Therefore, the use of a gas blanketing system on the tanks could assist in alleviating the majority of these issues and other potential issues that could cause oxygen ingress.

Compressor selection plays a critical role in the overall efficiency of the mVRU. The ability to effectively handle wet gas (condensate/water) is essential in this application. The wet gas in this application tends to foul the valves and seals in reciprocating compressors, and condensate falls out in the crankcase and compromises the lubricating oil, resulting in component failure. Reciprocating compressors are most effective in dry gas (absent of condensate) applications, but ultimately are found to be unreliable for mVRU service.

One recent change that has made a significant difference in mVRU accuracy is with pressure sensors. Due to the extremely low operating pressures encountered when capturing vapors, the early pressure-sensing devices were large and somewhat cumbersome pilot valves. These pilots were essentially mechanical devices that utilized moving parts, which were subject to corrosion and fatigue. Electronic transmitters have replaced pilots and operate much more reliably at extremely low pressures. With essentially no moving parts, they are better suited for the application and require dramatically less maintenance. The accuracy of these devices is far better than pilot valves, and enables more finite control of the mVRU to adapt to tank pressures fluctuations. Variable speed drives on electric-driven compressors have been another important advancement in mVRU technology. These new drives enable more turndown capability to respond to the daily variations in pressures associated with the process vessel being controlled. The ability to control the speed of a compressor as a result of the changing tank conditions allows for a more flexible unit. Variations in pressures and volumes can occur multiple times within a tank resulting from seasonal temperature changes or changes in production. Therefore, having the capability to vary the operating speed of the compressor to respond to these changes is essential in capturing vapors under all operating conditions.

The typical design for an lVRU has the tank or loading rack set up so the vapors flow through a submerged reaction chamber, this interaction between the waste gas and the liquid within the reaction chamber creates an environment where the VOCs are absorbed/adsorbed. The design of the system should be consistent with the expected flow of the VOC source. Physical absorption depends on properties of the exhaust stream and the liquid such as density and viscosity, as well as specific characteristics of the hydrocarbons in the exhaust stream. These properties are temperature dependent. Lower temperatures generally favor absorption of hydrocarbons by solvent. Absorption is also enhanced by higher liquid-gas ratios and higher concentrations in the hydrocarbon stream. Chemical absorption may be limited by the rate of reaction, although the rate-limiting step is typically the physical absorption rate, not the chemical reaction rate. The vapor is recovered because the saturated liquid can then be put into the crude or condensate tank. The saturated liquid is high in BTU, and adds to the value of the produced liquid. The vapor is recovered when the crude or condensate is refined. In order to use the liquid system and claim 95 percent - 98 percent control efficiency the system must meet the manufacturer's design and pounds of VOC to pounds of liquid reactant specification. The replacement of the liquid must follow manufacture's recommended procedure. This involves a separate temporary system to capture the vapors during the refill. The record of proper design must be kept to demonstrate how the unit was designed and for what capacity. The record of liquid replacement must be kept, along with the calculations for demonstrating that the VOC to liquid ratio has been maintained. Additionally, the system must be tested to demonstrate the efficiency. The testing requires that a sample is analyzed using a piping instrumentation design (PID) and Method 21 or modified Method 21. Both the inlet and the outlet streams would need to be tested, and the difference would determine the efficiency. The equation is as follows: based on PID results, the mathematical equation to determine efficiency is *1-(inlet-outlet)/inlet*. This testing needs to be performed and results recorded to receive 95 percent control efficiency no longer than: vacuum truck emissions: after 20 loads have been pulled through the lVRU, for tanks: Produced Water - Monthly, Crude - Bi-Monthly, Condensate - Weekly. This testing needs to be performed and results recorded to receive 98 percent control efficiency no longer than: vacuum truck emissions: after 15 loads have been pulled through the lVRU, for tanks: Produced Water – 3 weeks, Crude - 10 days, Condensate - 5 days. One of the advantages of this type of system is that there are no emissions from a combustion device, it can take low levels of VOC in the vapor phase, and there is no expected "downtime" since a temporary system handles the VOCs during refilling.

In summary, VRUs are designed to capture vapors from process vessels such as oil/condensate tanks and produced water tanks. For this reason, the commission has decided that in order for a control device to be recognized as a basic VRU it must capture vapor and include a sensing device set to capture this vapor at peak intervals. The efficiency of the VRU to capture this vapor will increase as additional design parameters are utilized such as additional sensing equipment, a properly designed bypass system, an appropriate gas blanket, an adequate compressor selection, and variable speed drives for electric driven compressor units.

These additional design parameters should satisfy the following requirements in order for the commission to accept their efficiency rating. The sensing equipment should be sufficient to monitor vapor pressures within the controlled process vessels. The bypass system should initiate automatically and divert the discharge volume back to the suction scrubber allowing tank pressure to build back to the point at which compression occurs. Additionally the system should be configured to shut down before any type of vacuum is reached to avoid pulling oxygen into the tanks, or imploding them. The use of a gas blanketing system on the tanks should be used to assist in alleviating the majority of any other issues that could cause oxygen ingress. Compressor selection should be made to sufficiently recover both wet and dry gas with minimal adverse impact on the compressor unit. Variable speed drives on electric-driven compressors are essential to respond to the daily variations in pressures associated with the process vessel being controlled.

For these reasons the commission is willing to accept that an applicant may claim up to 100 percent control efficiency for VRUs provided both the basic design function and additional design parameters of a VRU are satisfied. Records identifying these additional design parameters are utilized will need to be provided. Additionally, records demonstrating that all tank hatches and relief valves are sealed properly (according to design) must be maintained for this control efficiency to be recognized. For applicants wishing to opt-out of the record keeping requirement control efficiency up to 99 percent will be acceptable. For units which do not incorporate additional design parameters and/or maintain records of the VRU the commission cannot reasonably support control efficiencies greater than 95 percent.

The commission recognizes that there will be periods of VRU compressor maintenance and hence the capturing of vapors from the process vessels under control will cease. The agency has determined that this period of VRU compressor maintenance could potentially be for up to 5 percent of the year. As a result, the agency has determined that while a VRU may potentially attain a control efficiency of 100 percent this efficiency may only encompass approximately 95 percent of the year. These emissions are not considered MSS emissions because the emissions from the process vessels have not ceased only the control of these emissions have ceased. For this reason the emissions released from process vessels no longer under control are considered intermittent emissions representing an alternative operating scenario. Therefore, applicants must represent that these emissions are from an alternative operating scenario. Additionally, seals associated with VRU compressors must be accounted for and represented with fugitive emissions.

Thermal destruction units used at OGS include flares, thermal oxidizers, and vapor combustors. Subsection (e)(11) addresses the use of flares at an OGS. One of the most common add-on control devices is the basic candlestick flare which the commission will continue to allow for normal emission control. With basic pilot flame or ignition monitoring, a destruction efficiency of 98 percent for VOCs and H_2S may be assumed and 99 percent may be assumed for VOCs containing no more than three carbon atoms that contain no elements other than carbon and hydrogen. These destruction efficiencies are consistent with the *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers*, October 2000. The key elements of the commission's acceptance are in the design that ensures 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. Additionally, the requirements of 40 CFR §60.18 are found to be sufficiently attainable and necessary to achieve proper combustion for emergency flares to be held to the same requirements. The 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. Fuel for all flares shall be sweet gas or liquid petroleum gas except where only field gas is available and it is not sweetened at the site. 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 a flare tip, and this is insured through the basic continuous monitoring of the pilot flames with thermocouples or equivalent infrared monitors. The commission will allow automatic igniters like continuous sparking devices in lieu of a pilot flame. For all flares, records of the time, date, and duration of loss of the flare pilot flame must be recorded. The commission does not require temporary, portable, and backup flares that operate less the 480 hours per year to meet the monitoring requirements. The design still 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 under the PBR.

While the commission is aware of other forms of flares the commissions opted to represent the most commonly seen flare units in this evaluation. The commission recognizes that this is an ever improving form of control. For this reason, the commission hopes that, with the assistance of the regulated community and industry suppliers, we will better be able to authorize this ever improving control device.

The rule also requires that flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, consistent with the 40 CFR §60.18 requirement. If visible emissions are present for longer than the time period stated here, the commission agrees this is an indication of incomplete combustion, demonstrating that the waste gas is not being sufficiently destroyed.
Acid gas flares which must comply with opacity limits and records in accordance with §111.111(a)(4), relating to Requirements for Specified Sources, regarding gas flares, are exempt from this visible emission limitation.

Thermal oxidation and vapor combustion control devices are allowable control devices in subsection (e)(12). 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, operated, and monitored as discussed below, the commission believes efficiencies from 90 percent to 99.9 percent can be effectively achieved. Any design where the applicant documents its device's expected efficiency with the variability of the waste gas streams to be controlled may claim up to 90 percent 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 percent 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 percent if enhanced monitoring is utilized and the device is designed with ports and platforms to allow stack testing. This should ensure the fire box or fire tube is burning sufficiently hot enough and for a long enough time to achieve destruction. 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 parts per million by volume (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. Even with alternate temperatures and residence times, destruction efficiencies up to 99.9 percent may be demonstrated with enhanced monitoring and stack testing.

The commission has renamed subsection (f) and consolidated all notification, certification, and registration requirements. Subsection (f)(1) requires submittal of a basic identifying information notification via the ePermits system no later than January 1, 2013. The commission has moved the details of notification for existing, unchanged sites in subsection (b)(7)(B) to subsection (f)(1) and revised the name of the ePermits notification to "OGS Historical Notification" to clarify that this requirement is only for historical claims, not new projects. The commission has clarified that the notification is expected only for actively operating sites which have never been registered. Inactive sites are not included in this requirement. While equipment may remain in these locations, since they are not producing petroleum products, there are no expected emissions other than the safety valves and flanges holding pressure on the well. Finally, the commission has also clarified that groups of facilities as identified in subsection (c)(4) and have been determined to be negligible and excluded from most of the PBR requirements, are also excluded from historical notification expectations.

The commission also adopts subsection (f)(1) to determine where all OGS are located and what authorization mechanism they are claiming. To ensure an accurate accounting for all oil and gas entities authorized in Texas, the commission requires 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 all of the information needed to address issues with OGS areas throughout the state. At no time has the commission had a complete inventory or list of all OGS. The commission will establish a form and process through the ePermits system of the agency. The deadline is January 1, 2013. There is no fee required with this notification. This is a reasonable period to submit this information on OGS operations throughout the state. The commission has clarified in subsection (f)(1)(B) that locations which have been previously registered are not expected to submit information, unless the Central Registry specifically requires updates.

Subsection (f)(2) establishes the requirements for OGS if no other changes except for authorizing planned MSS occurs at an existing site authorized under this section, or any previous version of this section. Records demonstrating compliance with subsection (i) must be kept. If the existing OGS is certified, an addendum to the OGS certification may be filed using Form APD-CERT. No fee is required for this updated certification. These requirements apply no later than January 5, 2012. The authorization of planned MSS associated with existing OGS does not by itself require a notification or registration. The commission requires records to be kept on site and made available upon request. If the site has previously certified federally enforceable emission limits, an addendum to this certification may be filed to establish additional enforceable limitations for planned MSS. This certification may be filed by hard-copy, or through the electronic ePermit system. At this time, no fee is required for this certified update; however a detailed review of this information will not be performed, although random audits by field investigators and permitting staff may occur. This adoption also allows OGS with regular NSR 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 potentially insignificant emissions. Planned MSS shall be incorporated at the next revision or update to a registration under this section after January 5, 2012.

Subsection (f)(3) establishes the requirements for facilities authorized under §116.111 of this title. Only records of MSS as specified in this section must be kept. Planned MSS shall be incorporated into the permit at the next permit renewal or amendment after January 5, 2012.

Subsection (f)(4) establishes the requirements for notification of future construction or implementation of changes at an OGS. Any OGS meeting these requirements must notify the agency prior to construction or implementation of changes through the ePermits system (or if not available, hard-copy) using the "New Project Notification." The submittal of core data, predicted authorization mechanism, and a general description of the project is all the information that will be needed. This requirement gives flexibility to industry in timing and ensures the appropriate authorization method is chosen. It also ensures that the commission has the opportunity to audit emission estimates within a reasonable period of time from start of operation. The total fees for this notification will be $25 for small businesses (as defined in §106.50) or $50 for all others.

Subsection (f)(5) establishes the requirements for any registration that meets the emission limits of Level 1 as required in subsection (g). Any OGS meeting these requirements must register with the commission no later than 180 days after start of operation or implemented changes (whichever occurs first) through the ePermits system (or if not available, hard-copy) using the "Air Permits Division OGS PBR Level 1 and 2 Registration." The 180-day registration deadline is set with consideration to the time it typically takes for an operator to determine the production of a well or group of wells. The registration will consist of detailed summary of maximum emissions estimates based on: site-specific or defined representative gas and liquid analysis; equipment design specifications and operations; material type and throughput; and other actual parameters essential for accuracy for determining emissions and compliance with all applicable requirements of this section. Any OGS that meet the emission limits of Level 1 will have the same fees required in §106.50 to further incentivize the use of this Level. The total fees for this registration will be $25 for small businesses (as defined in §106.50 of this title) and $175 for all others.

Subsection (f)(6) establishes the requirements for any registration that meets the emission limits of Level 2 as required in subsection (h). Any OGS meeting these requirements must register with the commission no later than 90 days after start of operation or implemented changes (whichever occurs first) through the system (or if not available, hard-copy) using the "Air Permits Division OGS PBR Level 1 and 2 Registration." The 90-day registration deadline is set with consideration to the time it typically takes for an operator to determine the production of a well or group of wells. The registration will consist of detailed summary of maximum emissions estimates based on: site-specific or defined representative gas and liquid analysis; equipment design specifications and operations; material type and throughput; and other actual parameters essential for accuracy for determining emissions and compliance with all applicable requirements of this section. The total fees for this registration will be $75 for small businesses (as defined in §106.50) and $400 for all others.

Subsection (f)(7) was originally proposed as subsection (h)(3) which establishes specific scenarios under which registrations must be certified. Subsection (f)(7)(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 scenarios described below.

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 allow 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 standard (40 CFR Part 60 NSPS, 40 CFR Part 61 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 30 TAC 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, TCEQ Regional Office 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 involve compliance issues, in many cases TCEQ Regional Office al Offices may request that PBRs be certified to ensure awareness of the requirements and expectations. The final adopted 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.

The commission has added subsection (f)(8) to clarify that if the ePermits system is not available for more than 24 hours, or a operator does not have access to the internet, any of the required submittals may be provided by hard copy received through first-class mail. Subsection (f)(9) has been added in response to comments to allow for a limited time during which a company can change a notification intent to a different level of the PBR or standard permit while maintaining compliance. The commission will allow companies to update their authorization mechanism by submitting a revision to the PBR or an application for a standard permit within 90 days from the initial notification of construction of an OGS. For those OGS which have a change of production or installation of additional equipment which changes their authorization mechanism, a revision to the PBR or an application for a Standard Permit must be submitted within 90 days of the change of production or installation of additional equipment.

The commission adopts subsection (g) to establish the criteria for Level 1 of the PBR. The subsection name has been changed from "Post-Construction Registration" to "Requirements." Any OGS meeting these requirements must first notify the commission through the ePermit system, give the intended design of the site, registration, and project, estimate the emissions, and receive the auto-response for the intent to construct. After construction is complete, the owner/operator must the register with the commission no later than 180 days or 90 days, depending on emissions, after start of operations. The commission will establish the forms and processes through the ePermit system of the agency. Paper forms or mailings will follow established agency guidelines. Along with the registration, companies would be required to include a detailed summary of maximum emissions estimates based on: site-specific or defined representative 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 commission has the opportunity to audit emission estimates within a reasonable period of time from start of operation. Level 1 of the PBR is intended to require minimal delay in processing paperwork, corresponding to the limited amount of emissions released by the OGS. The commission adds that emissions must meet the impacts limitations of subsection (k) as further explained. The commission updates subsection (g) with emission limits, including requirements moved from subsection (k), as further explained. The commission revises subsection (g) to clarify that major source determinations should be based on all facilities associated with the registration, and may be further limited based on a company's certified values. The commission changes and moves registration and ePermit requirements to subsection (f), as explained under subsection (f). For clarification, the commission adds that all emissions estimates must be based on representative worst-case operations and planned MSS activities.

The commission adopts subsection (g)(1) that 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 provision also prohibits OGS from using Level 1 for sites which are major for the federal operating permit program. This requirement establishes clear minor source status through the rule. The commission adopts subsection (g)(1)(A) as initially proposed and changes subsection (g)(1)(A) to subsection (g)(1).

Subsection (g)(2) establishes that emissions from Level 1 PBR must meet the limitations established in subsection (k). These limitations are further described in subsection (k), which covers impacts from Oil and Gas operations on both receptors and Ambient Air Quality Standards. The commission adopts subsection (g)(2) and moves registration and ePermit requirements, including timeliness requirements, to subsection (f). The commission does not adopt any limitations on what facilities can be authorized under subsection (g). In response to comments, the commission determines that there is no justification for arbitrarily restricting the types of facilities under subsection (g). The commission adopts the addition of language that clearly indicates emissions limits are to be calculated after any operator limitations or controls. In response to comments, the commission determines that the added language is needed for clarification of meaning and intent. Additionally, the commission changes subsection (g)(2) to subsection (g)(3).

Subsection (g)(3) establishes that the maximum emissions from Level 1 OGS. This limits the annual emission of all VOCs to 15 tpy. The adopted annual limit on VOC assures minor source status along with Level 1 PBR sites being the lowest level of PRB authorizations. The commission adopts an annual limit of 15 tpy of VOCs, an hourly crude oil or condensate steady state VOCs limit of 100 lb/hr, total natural gas steady state VOCs limit of 204 lb/hr, and a total VOCs limit of periodic intermittent operations of 145 lb/hr for condensate and 750 lb/hr for natural gas for up to 150 hours per year. This subsection limits the annual emission of all VOCs to 15 tpy. The commission revises the annual value in response to comments and establishes the annual value at 15 tpy to include 5 tpy products of combustion in addition to 10 tpy petroleum releases. The adopted annual limit on VOC assures minor source status along with Level 1 PBR sites being the lowest level of PBR authorizations. The commission adopts an hourly crude oil or condensate steady state VOCs limit of 100 lb/hr at 1/4 mile. Periodic intermittent operations in low pressure scenarios are established at 145 lb/hr and high pressure to 318 lb/hr for up to 150 hours per year based on applicable dispersion columns at 1-mile distance. The limits on total natural gas steady state VOCs are 204 lb/hr, and periodic releases operations in low pressure scenarios to 750 lb/hr and high pressure to 1635 lb/hr. The commission has added the hourly limit on natural gas, crude and condensate based on comments, instead of a generic total VOC value. The commission has revised the rule in response to comments, and the values adopted are more representative of the actual emissions released. Natural gas condensate typically consists more than 80 percent of C_4-C_8 alkanes and small fraction of BTEX. C_4-C_8 alkanes have relatively low acute respiratory effects compared to BTEX. High concentrations of these alkanes may cause temporary irritation of the nose and throat and headache, nausea, dizziness, drowsiness, anesthesia, and confusion. The current (interim) short-term ESL (3,500 $\mu g/m^3$) was set based on the weight percent of components in typical sweet natural gas condensate. The ESL was developed by calculating each component's weight percent and its respective ESL using a formula for the derivation of a chemical product. While the current short-term ESLs for C_4-C_8 alkanes are much higher than those for BTEX, they are overly conservative. The new short-term ESLs for C_4-C_8 alkanes, if developed following the 2006 TCEQ Guidelines to Develop ESLs and Reference Values, may be higher approximately by a factor of two to three. Consequently, the short-term ESL for condensate may be higher if derived based on higher C_4-C_8 alkanes' ESLs. Moreover, since the short-term ESL for natural gas condensate is primarily driven by the BTEX's ESLs, if the short-term ESL for benzene is met, the short-term impacts for condensate emissions from OGS facilities are expected to be protective. The current (interim) short-term ESL (3,500 $\mu g/m^3$) for crude oil was derived based on available occupational exposure limits for similar petroleum hydrocarbons (e.g., gasoline, naphtha, and kerosene) which is conservative. The new short-term ESLs for crude oil and other similar petroleum hydrocarbons, if developed following the 2006 TCEQ Guidelines to Develop ESLs and Reference Values, may be higher approximately by a factor of two to three. Therefore, a higher hourly emission rate for crude oil emissions is expected to be protective. The hourly limit for periodic intermittent operations should be high enough to cover emissions from low pressure operations such as truck loading and MSS activities such as blowdowns, pigging and purging. The most substantial hourly sources of VOCs at OGS, based on a review of 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 of the impacts tables. Since truck loading, along with MSS, are not steady state operations and are only expected to happen for a limited amount of time, typically less than one hour, intermittent, periodic operations are allowed a higher hourly limit, but only for a limited time during the year. Additionally, high pressure pipeline or equipment releases also occasionally occur and have high hourly releases and appropriate values have been included to cover these periodic emissions and ensure protectiveness. These emissions are still subject to the impact review under subsection (k). Site-wide hourly emission rate includes VOC emissions from engine, turbines, and other combustion devices as un-combusted natural gas.

In response to comments, the commission re-evaluates and revises the generic OGS evaluation used for modeling, development of the impact tables, and corresponding emission limits of the PBR. The commission bases the new VOCs limits on the revised generic OGS evaluation and on the necessary, subsequently developed tables due to the revised generic OGS evaluation. In response to comments, the commission revises the VOC limits to account for various mixtures and corresponding ESLs (crude oil, condensate, natural gas) as well as steady-state and periodic intermittent releases. The commission bases steady-state releases of VOCs on a distance of approximately 1/4 mile (1400 feet) from the project and the highest two contributing sources (flash from storage tanks and process vessels with a 20-foot release height). For natural gas, the commission determines that the highest two contributing sources are flash from storage tanks (112 lb/hr) and process vessels (295 lb/hr), with an average limit of 204 lb/hr used as a rule limit. The commission determines that periodic releases are typically truck loading or unit/pipeline purging and are based on a distance of 1 mile, resulting in 750 lb/hr and 1500 lb/hr for natural gas. Periodic emissions are also limited in the number of hours per year expected. The commission determines that the annual hours are based on a random review of over a hundred recently reviewed PBR registrations which have included voluntary planned

MSS or truck loading where the total number of hours per year with those activities ranged from 10 - 320 hrs and an average of 82 hours per year. The commission determines that typical VRU downtime is estimated at 1 - 5 percent of the year, or 88 - 438 hours. The commission determined that a total condensate or crude oil VOC limit of 145.0 lb/hr and 318 lb/hr for up to 150 hr/yr is an appropriate rule limits for these smallest of sites. Since these are meant to be the smallest of OGS, then they should only have minimal truckloading and MSS activities. If the site is large enough that it cannot do these activities in 150 hours per year, then the next highest authorization will need to be obtained. Since these are intermittent operations and not steady state, they are allowed a higher, but limited hourly emission rate since they still have to demonstrate compliance with impacts with ambient air quality standards. These periodic intermittent operations will do this demonstration by complying with subsection (k).

The commission adopts benzene limits in subsection (g)(3) based on an evaluation of the hourly and annual ESLs (170 $\mu g/m^3$ and 4.5 $\mu g/m^3$). Evaluation of the impacts tables shows 1.95 lb/hr and 2.8 tpy of benzene is protective at approximately 1/4 mile. Therefore the adopted limits of 1.95 lb/hr and 2.8 tpy for steady state operations and 7 lb/hr and 15.4 lb/hr for up to 150 hours per year for periodic operations for benzene are reasonable for small OGS. Since long-term exposure to benzene has shown to have health impacts, the commission is adopting both a short-term and long-term limit for benzene. OGS sites must demonstrate how they meet the impacts of both the short-term and long-term emission limits in subsection (k).

The commission adopts the limits of 4.7 lb/hr and 20.6 tpy for steady state operations and 5.1 lb/hr and 9.8 lb/hr for up to 150 hours per year for periodic operations for H_2S. These limits are based on the previously discussed ambient air standard compliance assurance. Again, the commission bases the H_2S limits on the revised generic OGS evaluation and on the necessary, subsequently developed tables due to revising the generic OGS evaluation and due to comments about the modeling methodologies for the tables themselves. 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 controlled truck loading and blowdowns. The commission determines that the highest contributing source of sulfur compound emissions, including H_2S emissions, is from flares and that a typical height for process flares is 40 feet, yielding H_2S emissions of 4.7 lb/hr use as a rule limit, corresponding to 20.6 tpy. The commission adopts the rule limit of 20.6 tpy H_2S because most sour sites with a flare are in less populated areas and should easily be able to meet the impacts analysis of subsection (k). Additionally, the commission changes subsection (g)(2)(B)(i) for H_2S limits to subsection (g)(3).

The commission adopts the limits of 47 lb/hr and 25 tpy for SO_2. 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 commission determines that the highest contributing source of sulfur compound emissions, including SO_2 emissions, is from engines and that a typical height for the stack is 18 feet, yielding SO_2 emissions of 47 lb/hr. It is assumed that most SO_2 comes from steady state operations such as combustion units. Periodic releases are also included at 93.2 lb/hr based on larger engine hp at 1 mile to a property line. Additionally, the commission changes subsection (g)(2)(B)(ii) for SO_2 limits to subsection (g)(3).

In response to comments, the commission adopts the limits of 43.2 lb/hr and 100 tpy for NO_X. This was in response to comment and the re-evaluated generic OGS. 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. 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 adopting 100 tpy of NO_X to assure minor source status with respect to Title V. The commission determines that NO_X limits can be based on the NO_2 hourly NAAQS standard as released from a typical engine of 1,250 hp with an 18-foot release point at 1,400 feet (approximately 1/4 mile) from the project and capped at less than 100 tpy to ensure no registration is applicable to Title V federal operating permits. In response to comments and numerous sampling reports submitted, the commission also bases the NO_X emission limits on the highest probable NO_2 to NO_X ratio of 50 percent. Additionally, the commission changes subsection (g)(2)(C)(i) for NO_X limits to subsection (g)(3).

In response to comments, the commission adopts the limits of 45 lb/hr and 100 tpy for CO. The commission bases CO limits on an annual Title V federal operating permits applicability level of 100 tpy, corresponding to 22.8 lb/hr. The commission chose to almost double the 22.8 lb/hr to 45 lb/hr to allow for operational flexibility of having all combustion units at OGS running at the same time. The commission determines that the CO limits can be based on the NAAQS as released from a typical engine of 1,250 hp with an 18-foot release point at 1,400 feet (approximately 1/4 mile) from the project, which is 4,592 lb/hr. Additionally, the commission changes subsection (g)(2)(C)(ii) for CO limits to subsection (g)(3).

For Level 1 registration, the commission adopts a limit of 10 lbs/hr and 5 tpy PM_{10} and $PM_{2.5}$ as a limit for the smallest sites. In response to comments, the commission adopts the limits of 10 lb/hr and 5 tpy for PM_{10} and $PM_{2.5}$ emissions. This was in response to comments and the re-evaluated generic 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 and the assumption that all PM_{10} is $PM_{2.5}$, the commission bases the PM_{10} and $PM_{2.5}$ limits on the most stringent of the respective promulgated NAAQS as released from a typical large engine with a 20-foot release point at 1,400 feet (approximately 1/4 mile) from the project, or 6.4 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 bases the 5 tpy limit on a reasonable value that allows even more than the largest OGS could emit in particulate matter. Over 100 OGS were reviewed for particulate matter emissions, and articulate matter emissions are not a concern at OGS. Additionally, the commission changes subsection (g)(2)(C)(iii) for PM_{10} and $PM_{2.5}$ limits to subsection (g)(3).

The commission has changed subsection (g)(3) in response to comments with regard to requirements for a specific check of formaldehyde impacts. After a detailed review of submitted information and federal background documents for 40 CFR 63 NESHAP Subpart ZZZZ, the commission has determined that the requirements of this federal standard is sufficient to establish controls on formaldehyde on new and existing engines. This is further supported by recent monitoring does not show any concerns with monitored values of formaldehyde from engines associated with oil and gas production sites. Therefore, formaldehyde is omitted from the impacts evaluation requirements and emission limits for this PBR.

The commission adopts subsection (h) to establish the criteria for Level 2 of the PBR. Any OGS meeting these requirements must first notify the commission through the ePermits system, give the intended design of the site, registration, and project, estimate the emissions, and receive the auto-response for the intent to construct. After construction is complete, the owner/operator must the register with the commission no later than 90 days after start of operations. The commission will establish the forms and processes through the ePermits system of the agency. Paper forms or mailings will follow established Agency guidelines. Along with the registration, companies would be required to include a detailed summary of maximum emissions estimates based on: site-specific or defined representative 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 commission has the opportunity to audit emission estimates within a reasonable period of time from start of operation. The commission adds that emissions must meet the impacts limitations of subsection (k) as explained below. The commission updates subsection (h) with emission limits, including requirements moved from subsection (k), as explained below. The commission changes and moves registration and ePermits requirements to subsection (f), as explained under subsection (f). For clarification, the commission adds that all emissions estimates must be based on representative worst-case operations and planned MSS activities.

The commission for Level 2 adopts subsection (h)(1) to limit 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 (equal to or 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 adopts subsection (h)(1) as initially proposed.

The commission for Level 2 changes subsection (h)(2), for clarity, to read emissions must meet the limitations of subsection (k). The commission moves the registration requirements of subsection (h)(2) to subsection (f), as explained in subsection (f). The commission moves and changes the emission limits under subsection (h)(2) to subsection (h)(3).

The commission adopts, in subsection (h)(3), the Level 2 annual limit of 25 tpy of VOCs, an hourly crude oil or condensate VOC limit of 100.0 lb/hr, a total natural gas VOC limit of 356 lb/hr for steady state operations, a total VOC limit of 145.0 lb/hr for condensate and 750 lb/hr for natural gas for up to 300 hours per year for low pressure periodic intermittent operations, and 318 lb/hr for condensate or crude oil and 1635 lb/hr for natural gas for high pressure periodic releases. Natural gas condensate typically consists more than 80 percent of C_4-C_8 alkanes and small fraction of BTEX. C_4-C_8 alkanes have relatively low acute respiratory effects compared to BTEX. High concentrations of these alkanes may cause temporary irritation of the nose and throat and headache, nausea, dizziness, drowsiness, anesthesia, and confusion. The current (interim) short-term ESL (3,500 $\mu g/m^3$) was set based on the weight percent of components in typical sweet natural gas condensate. The ESL was developed by calculated by each component's weight percent and its respective ESL using a formula for the derivation of a chemical product. While the current short-term ESLs for C_4-C_8 alkanes are much higher than those for BTEX, they are overly conservative. The new short-term ESLs for C_4-C_8 alkanes, if developed following the 2006 TCEQ Guidelines to Develop ESLs and Reference Values, may be higher approximately by a factor of two to three. Consequently, the short-term ESL for condensate may be higher if derived based on higher C_4-C_8 alkanes' ESLs. Moreover, since the short-term ESL for natural gas condensate is primarily driven by the BTEX's ESLs, if the short-term ESLs for BTEX are met, the short-term impacts for condensate emissions from OGS facilities are expected to be protective. For these reasons, a higher hourly emission rate for condensate emissions is deemed allowable. The current (interim) short-term ESL (3,500 $\mu g/m^3$) for crude oil was derived based on available occupational exposure limits for similar petroleum hydrocarbons (e.g., gasoline, naphtha, and kerosene) which is conservative. The new short-term ESLs for crude oil and other similar petroleum hydrocarbons, if developed following the 2006 TCEQ Guidelines to Develop ESLs and Reference Values, may be higher approximately by a factor of two to three. Therefore, a higher hourly emission rate for crude oil emissions is expected to be protective.

The commission adopts subsection (h)(3) Level 2 an annual limit of 25 tpy of VOCs. The adopted 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 for sporadic or controlled emissions from truck loading and blowdowns. The commission also evaluated the maximum condensate or crude oil emissions allowed under the impacts tables. Since the actual emissions from an OGS will result from a combination of sources, many with more effective dispersion, these values were determined by the commission to be an appropriate limit for this subsection. These values are also in the typical ranges of hourly emissions from a random sampling of PBR registrations in 2010. The same dispersion source characteristics were used as in Level 1, however a distance of 1/2 mile from the source was used for Level 2. The commission bases all steady-state releases of VOCs on a distance of approximately 1/2 mile (2,700 feet) from the project and the highest two contributing sources and on flash from storage tanks and process vessels with a 20-foot release height. For natural gas, the commission determines that the highest two contributing sources are flash from storage tanks (273 lb/hr) and process vessels (439 lb/hr), with an average limit of 356 lb/hr used as a rule limit. The commission determines that periodic releases are typically truck loading or unit/pipeline purging and are based on a distance of 1 mile and a typical 10-foot release height, but limited in number of hours per year expected for these smaller sites. The commission determines that the annual hours are based on a random review of over a hundred recently reviewed PBR registrations which have included voluntary planned MSS or truck loading where the total number of hours per year with those activities ranged from 10 - 320 hours and an average of 82 hours per year. The commission determines that typical VRU downtime is estimated at 1 - 5 percent of the year, or 88 - 438 hours. The commission determines that up to 300 hr/yr are appropriate rule limits for periodic intermittent operations. Since these operations are intermittent and not steady state, they are allowed a higher, but limited hourly emission rate since they still have to demonstrate compliance with impacts and ambient air standards. Most of these events take place in less than an hour, based on the above review of PBRs, but the whole hour was relied upon for demonstration of meeting impacts. These operations will still have to show that they are protective under subsection (k). Additionally, the commission changes and expands subsection (h)(2)(A) to subsection (h)(3).

For benzene, the commission determines that the highest two contributing sources for benzene are flash from storage tanks (2.6 lb/hr and 3.7 tpy) and process vessels (4.1 lb/hr and 6 tpy), yielding averages of 3.35 lb/hr and 4.8 tpy used as the rule limits. Additionally, the commission changes subsection (h)(2)(A)(i) for benzene limits to subsection (h)(3).

The commission has changed subsection (h)(3) in response to comments with regard to requirements for a specific check of formaldehyde impacts. After a detailed review of submitted information and federal background documents for 40 CFR 63 NESHAP Subpart ZZZZ, the commission has determined that the requirements of this federal standard is sufficient to establish controls on formaldehyde on new and existing engines. This is further supported by recent monitoring and does not show any concerns with monitored values of formaldehyde from engines associated with oil and gas production sites. Therefore, formaldehyde is omitted from the impacts evaluation requirements and emission limits for this PBR.

The commission adopts the limits of 6 lb/hr and 25 tpy for steady state operations and low pressure releases to 6 lb/hr and high pressure releases at 9.8 lb/hr for up to 300 hours per year for periodic operations for H_2S. These limits are based on the previously discussed ambient air standard compliance assurance. Again, the commission bases the H_2S limits on the revised generic OGS evaluation and on the necessary, subsequently developed tables due to revising the generic OGS evaluation and due to comments about the modeling methodologies for the tables themselves. 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 should be sufficient to allow a wider range of H_2S sources at a site. The commission determines that the highest contributing source of sulfur compound emissions, including H_2S emissions, is from flares and that a typical height for process flares is 40 feet, yielding H_2S emissions of 6 lb/hr use as a rule limit, corresponding to about 25 tpy, which also matches with the limit set in §106.4, Requirements for Permitting by Rule. Following the reasoning discussed for the Level 1 H_2S periodic limit, 5.1 lb/hr would be the limit, but since 5.1 lb/hr is less than the steady state hourly limit of 6 lb/hr, the low pressure periodic limit is also set at 6 lb/hr. Additionally, the commission changes subsection (h)(2)(B)(i) for H_2S limits to subsection (h)(3).

The commission for Level 2 adopts the limits of 63 lb/hr and 25 tpy of SO_2. 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 annual limit of 25 tpy was chosen to match with the limit set in §106.4, Requirements for Permitting by Rule. In response to comments, the commission re-evaluates and revises the generic OGS evaluation. The commission bases the SO_2 limits on the revised generic OGS evaluation and on the necessary, subsequently developed tables due to revising the generic OGS evaluation and due to comments about the modeling methodologies for the tables themselves. At a typical site total size of engines is likely greater than 1500 hp and with an 18-foot stack, the acceptable emissions would be 63 lb/hr. Periodic releases are also included at 93.2 lb/hr based on larger engine hp at 1 mile to a property line. Additionally, the commission changes subsection (h)(2)(B)(ii) for SO_2 limits to subsection (h)(3).

The commission for Level 2 adopts the limits of 54.4 lb/hr and 250 tpy for NO_X. 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 adopting 250 tpy of NO_X to assure minor source status with respect to PSD. The commission bases the NO_X limits on the revised generic OGS evaluation and on the necessary, subsequently developed tables due to revising the generic OGS evaluation and due to comments about the modeling methodologies for the tables themselves. The commission determines that NO_X limits can be based on the NO_2 hourly NAAQS as released from a typical engine of 1,250 hp with an 18- foot release point at 2,700 feet (approximately 1/2 mile) from the project yielding 54.4 lb/hr used as a rule limit and capped at less than 250 tpy to ensure no registration is applicable to PSD requirements. In response to comments and numerous sampling reports submitted, the commission also bases the NO_X emission limits on the highest probable NO_2 to NO_X ratio of 50 percent. Additionally, the commission changes subsection (h)(2)(C)(i) for NO_X limits to subsection (h)(3).

The commission adopts the following for Level 2 CO emissions limits. CO emissions are limited to 104 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 adopted limits are NAAQS compliant and should allow for both small and large engines at an OGS. Furthermore, the commission is adopting 250 tpy of CO to assure minor source status with respect to PSD. The commission bases the CO limits on the revised generic OGS evaluation and on the necessary, subsequently developed tables due to revising the generic OGS evaluation and due to comments about the modeling methodologies for the tables themselves. The commission determines that CO limits can be based on the CO hourly NAAQS as released from a typical engine of 1,250 hp with an 18- foot release point at 2,700 feet (approximately 1/2 mile) from the project yielding 104 lb/hr and capped at less than 250 tpy to ensure no registration is applicable to PSD requirements. Additionally, the commission changes subsection (h)(2)(C)(ii) for CO limits to subsection (h)(3).

Based on the following 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 for Level 2 adopts a limit of 12.7 lbs/hr and 10.0 tpy PM_{10} and $PM_{2.5}$. 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. In response to comments, the commission re-evaluates and revises the generic OGS evaluation. The commission bases the PM_{10} and $PM_{2.5}$ limits on the revised generic OGS evaluation and on the necessary, subsequently developed tables due to revising the generic OGS evaluation and due to comments about the modeling methodologies for the tables themselves. The commission bases the PM_{10} and $PM_{2.5}$ limits the most stringent of the respective promulgated NAAQS standard as released from a typical large engine with a 20- foot release point at 2,700 feet (approximately 1/2 mile) from the project, or 12.7 lb/hr which is used as a rule limit. The 10 tpy limit is based on the most stringent of tpy limits for PM_{10} and $PM_{2.5}$ established by the EPA for $PM_{2.5}$. Additionally, the commission changes subsection (h)(2)(C)(iii) for PM_{10} and $PM_{.5}$ limits to subsection (h)(3).

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 PBR, then MSS activities and associated emissions for that site need to be either registered or addressed in a registration. To assist companies in calculating their MSS emissions the agency is building MSS estimation methods into the emission calculations spreadsheet and published the draft on the agency website for external stakeholder input as of October 29, 2010. The commission will also provide checklists and guidance documents that will be available on the TCEQ website. In addition, the commission is planning on sponsoring short workshops around the state to assist companies in preparing registrations and compliance records before the effective date of the rules. The commission requested comments and technical information on activities and potential emissions from planned MSS because of the limited information available on the various planned MSS activities which occur throughout the oil and gas industry. The commission did not receive any information in response to this request and the rule has not changed.

The commission adopts 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. The commission has revised subsection (i)(2)(C) in response to comments and has determined that references to §106.263 are not necessary as control expectations are covered sufficiently by subsection (e)(8) - (12).

Planned MSS activities with negligible emissions are authorized by 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; 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 commission. Other planned MSS activities with negligible emissions are based on the commission'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 commission requested comments and further 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. The commission did not receive any information in response to this request and the rule has not changed. 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 commission may reopen this PBR to reevaluate other MSS activities with negligible emissions. The commission has removed amine and other treatment chemicals replacement (except glycols) and hot oil treatments from this subsection. The commission evaluated the potential for emissions from replacing amine and other treatment chemicals and does not believe there is sufficient emission potential to warrant accounting of this activity for a PBR. The commission is not comfortable adding an exemption for heavier oils or smaller vessels for MSS because the approach to clearing is not regulated in the PBR. Liquid heals and clinging in vessels can represent significant emissions if forced into the atmosphere for clearing or cleaning purposes.

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 a large amount of associated purging (blowdown) of VOCs, since the materials would be shifted to another part of the OGS. This subsection has been updated to state that engine/compressor shutdowns shall result in no greater than 4 lb/hr of natural gas emissions instead of stating that the shutdowns shall not result in emissions. This value should allow for a small amount of emissions from shutdowns and still includes a reasonable amount of VOC emissions justifiable to be authorized under this circumstance. The 4 lb/hr value is consistent with the value from the natural gas impacts table for fugitive dispersion characteristics at the shortest distance, 50 feet, and a 3-foot release height. Startup 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 percent, they are substantially minimized. If companies operate in this manner, the registration should specify all details and emission estimates.

The commission requested comments and technical information on activities and potential emissions from planned MSS because of the limited information available on the various planned MSS activities which occur throughout the oil and gas industry. The commission did not receive any information in response to this request and the rule has not changed. 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 adopted 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 (m)) and in monitoring and recordkeeping (specified in Table 8 of subsection (m)). All necessary records, which include documentation of all sampling and monitoring, must be continuously 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, and maintained, and inspected.

The commission changes the requirements for a run time meter for Boiler, Reboilers, Heater-Treater, and Process Heaters. In response to comments, the commission adopts a requirement for a monitor only if a registration relies on less than full year operation and maximum capacity when calculating emissions. Also, the adopted rule expands the examples of process monitors beyond run time meters. Also the commission clarifies that no records of hours of operation must be kept for engines that have no sampling requirements in Table 7 of subsection (m). The commission adopts a run time meter for Gas Fired Turbines, but in response to comment the commission adopts a requirement for a meter only for turbines greater than 500hp only if the registration relies on less than full year operation and maximum capacity when calculating emissions and expands the examples of process monitors. The commission's intent is to require a practically enforceable permit condition for facilities that are registered at less than full potential to emit in cases such as artificially limiting operation to avoid stricter rules.

Each specific sampling, monitoring, and recordkeeping requirement varies based on related effects, accurate compliance demonstrations, and protectiveness and includes the following items at a minimum: an up-to-date site layout including the configuration of all equipment and process units within the site because any changes to the site layout such as the distance of a unit to a receptor or property line may affect emission impacts; the property line and nearest off-site receptors must be shown because impacts of contaminants 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. This will also establish the boundary to conduct impacts assessments. 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 contaminant emissions are represented. This information is important to determine appropriate maximum acceptable emissions of all authorized facilities. This information does not need to be done by a professional such as a draftsman, it just needs to demonstrate the necessary information. The records need to be kept where they are easily accessible to Regional or Local personnel.

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 Procedure Manual, which can be found in "Chapter 2, Stack Sampling Facilities" available at : *http://www.tceq.state.tx.us/compliance/field_ops/acguide.html*, "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 after the initial start of operation of implementation of a change which required the registration. This time frame allows for scheduling testers, coordinating with the Regional Office and 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. Normally, 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 40 CFR Part 60 NSPS and 40 CFR Part 61 NESHAP standards, other PBRs, typical permit conditions, 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 TCEQ 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 Region Office 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 regional 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 14 portions of the Sampling Procedure Manual can be found at *www.tceq.state.tx.us/compliance/field_ops/acguide.html*. Finally, results are required to meet National Environmental Laboratory Accreditation Conference (NELAC) certification requirements found in 30 TAC Chapter 25, Environmental Testing Laboratory Accreditation and Certification. That does not mean all data must come from a NELAC certified lab. Rather, Chapter 25 explains when that certification must be applied. This requirement in the PBR is no more than what 30 TAC Chapter 25 requires.

Sampling of gas and liquid streams from appropriate process sampling points is required in order to determine composition or and other properties such as heat content, specific gravity, and vapor pressure which are needed to estimate emissions. It is essential that stream lab analyses/reports include a measurement of H_2S, individual HAPs, and at least all those hydrocarbons containing at least up to at least 10 carbon atoms per molecule (C10+). This analysis will give the BTEX, specifically benzene analysis needed for impacts evaluations. 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 processes. 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 from that process. 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 parameters are not representative of the actual conditions do not match then there is no way to verify how accurate the emission estimates are. Potential to emit for PBRs is usually 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. For example, 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. For example, the outlet gas flow speciation from the emission calculations output of GRI-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 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 bulk 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 percent of the needed material). The resulting uncontrolled emissions based on this analysis (normalized to reflect 100 percent) yielded emissions levels so high that air standards and screening levels would not be attainable without highly restrictive 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 40 CFR Part 63 MACT applicability. 40 CFR Part 63 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 obtained 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 overestimate impacts from emissions such as BTEX. This over estimation could needlessly trigger federal applicability standards resulting in greater cost of control.

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 obtained 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/ by volume of H_2S at 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 estimates must be obtained. The choice of analysis is the Tutwiler, Stain Tube, or full sulfur analysis. The traditional method was to perform 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 flashes from the liquid concentration in 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.

Required site-specific or defined representative gas and liquid analysis goes together with the record requirement for equipment specifications. The volumes and pressures, material compositions of the vessels to be depressurized, purged or degassed and emptied for MSS are directly related to the emission rate estimated. The control equipment specifications from the manufacturer or design should match with the flow, temperature, and pressures measured and coming process equipment for normal and, as applicable MSS, 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, and 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 affect 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 affect on emission rates. Testing and quarterly performance evaluations of engines are adopted 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, only 50 percent 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. In response to comment, the commission adopts a clarification that initial sampling for engines may be performed on-site if no previous sampling reports are available. Also, the commission adopts a clarification that initial and periodic sampling is not required for emergency engines and that idled engines do not need to be restarted solely for the purpose of testing. Additionally, the commission adopts language to allow a period of time after restarting an engine for sampling to occur in order to accommodate the scheduling issues noted in the comments. Proper on-site operation would include demonstration of compliance with health-based ESLs for total VOC (as natural gas) and formaldehyde emissions and property line standards for NO_X and SO_2 emissions. Proper on-site operation would include demonstration that controls are operating properly. However, the commission 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 commission is not requiring individual engines to be tested for formaldehyde, but the commission intends to work with engine manufacturers to establish appropriate emission factors for specific engine models. The commission received some information on formaldehyde for the two main engines type, rich-burn and lean-burn, and given the consistent performance of each engine type, the commission will not require testing on every engine. The commission adopts initial sampling requirements for VOC from engines turbines in subsection (m) Table 7, "Sampling and Demonstrations of Compliance." In response to comment, the commission adopts no requirement for sampling VOC from engines and turbines. The commission believes carbon monoxide (CO) is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The additional cost of monitoring for VOC has been eliminated but registrations still must contain appropriate estimates of emissions. Periodic monitoring of engines is needed to ensure ongoing performance. The methods described in the proposal are 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 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. The commission adopts a clarification in the engines periodic evaluation section of subsection (m) Table 7 to state that these evaluations only need to be performed on engines that have a standard in subsection (m) Table 6. The commission adopted quarterly periodic evaluations for all engines with a standard in subsection (m) Table 6. In response to comment, the commission adopts quarterly periodic evaluations only for engines at sites that have a federal operating permit. Overall, quarterly testing under the OGS PBR is less stringent or as stringent as associated periodic monitoring choices in the oil and gas GOPs. Since sites with federal operating permits necessarily emit more pollution than sites without those permits, the commission believes it is appropriate to require enhanced monitoring. The commission proposed the use of only portable analyzers conforming to federal quality assurance procedures for periodic evaluations. In response to comments, the commission adopts the use of portable analyzers operated according to manufacturer's instructions or the use of stain tubes for periodic evaluations. The commission agrees with commenters that prescriptive analyzer methodology like Conditional Test Method 034 may not lead to any different results than a company-developed method. However, the commission adopts language that any modifications to the portable analyzer manufacturer's instruction such as calibration procedures must not have a negative effect on results. Also, the commission agrees with commenters that portable analyzer monitoring represents unnecessary additional cost for sites that do not currently use them for compliance with other rules. The commission believes that for the purposes of a PRB colorimetric tests (stain tubes) offer a reasonable assurance of compliance. The commission proposed periodic evaluations after engine maintenance. In response to comments, the commission adopts no requirement. The commission agrees with commenters that the majority of engine maintenance has a positive or neutral affect on emissions. The commission adopts a Combustion Device biennial testing requirement. The commission adopts a clarified header, Engines and Turbines. The commission also adopts grammatical changes to the engine and turbine biennial testing language in subsection (m) Table 7 for ease of reading.

For thermal oxidizers claiming efficiencies greater than 98 percent 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 increase in pollution effect during periods of non-combustion does not occur. Reasonable temperature accuracy for high temperature monitors has been ±0.75 percent or ±10.5 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 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 95 percent is expected over rolling 12-month periods.

Records of unit parameter adjustments must be maintained because of the affect 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 the permit holder 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.

Tanks and vessels design data and inspections need to be kept on file. Volume, temperature, pressure, throughput, and material compositions that affect emissions for process vessels and tanks need to be recorded periodically in order to properly estimate normal production and MSS emissions. There should be a demonstrations/statement with supporting information in the file that any control equipment is properly sized to handle the production emissions. 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 including the condition of tank truck before loading (empty containing crude oil, condensate or another material's vapor from last load, degassed, or partially full with crude oil or condensate, etc.) and, amount and type of material being loaded must be maintained as well as the type of transfer used. If a control is not a dedicated or permanent control for loading, then the control utilized must be recorded for each loading operation. 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 the truck's pressure test. Additionally, record must be kept when vacuum trucks are using their normal vacuum air mover for loading or the vacuum truck is using an onboard pump or a portable pump to push material into the truck so that the appropriate method for estimating the emissions can be utilized.

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 unless actual 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 is 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 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 should be a demonstration/statement with supporting information in the file that any control equipment is properly sized to handle the MSS emissions. There is a potential for a large amount of emissions in a short period of time with these types of events.

MSS for Tanks, Vessels, or Other Facilities should indicate by have written records including the vessels and equipment degassed or purged including the volume and pressure (if applicable);

the volume of purge used and a description of the piping and equipment involved clarifying estimates for a coated surface or heel, the date, the emission estimate to atmosphere and to control; and when controlled, the control device. Where purging to a control device to meet a lower concentration before purging to atmosphere is conducted, the concentrations of VOC, BTEX or H_2S as appropriate must be measured and recorded prior to purging to atmosphere. Also when a control device is necessary to meet emission limitations, the device is subject to the requirements of subsection (e) and record requirements of subsection (m) Table 8.

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. The PBR also allows the use of automated igniting systems. The automated igniting systems must continuously monitor and record a parameter that indicates the spark or ignition system is functioning and can generate a record when the system malfunctions. Records should indicate when calibrations are conducted and note any corrections made. Where flows are not assumed to be continuous a record of the flows is needed to estimate emissions.

Thermal oxidizer exhaust temperature and a method of establishing hours of operation are the basic monitored parameters. Where intermediate efficiency is being claimed the combustion exhaust, temperature must be continuously monitored and recorded, comparison to 1400 degree F should be clear. For higher efficiency design and claimed control, 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. This information provides a certain record of highly efficient control in the unique cases where a company wants to claim and certify this level of control. Quality assurance, quality control, and all necessary maintenance of the monitors should be recorded.

Where a company elects to claim the highest efficiencies or wants to establish alternate temperatures, oxygen or CO at the high efficiencies, the testing records as noted above along with the parameters measured during the test need to be retained to justify maintain the efficiency claim.

In the situation where a company is using vapor recovery for control of process tanks and vessels that would normally vent to atmosphere, monitoring and records for control may be necessary. Specifically monitoring and records are required where the piping and 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. 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. This information can be demonstrated through the use of the E&P Tanks 2.0 program.

Occasionally, operations direct waste gas flows to process combustion devices like reboilers, heaters and furnaces for control. Glycol reboiler combustion is the most common device expected for this purpose. Where a company is claiming this control basic monitoring is any continuous monitor that indicates when the flame in the device is on or off (other than partial operational use). Partial operational use is where the combustion device cannot be assured to fully combust the waste gas stream when heat for the devices primary purpose is not needed. The following are effective basic monitors: a fire box temperature, rising or steady process temperature, CO, primary fuel flow, fire box pressure or equivalent. Enhanced monitoring for 91 to 99 percent control claims where waste gas is not introduced as the primary fuel must include the following monitors: continuous firebox or fire box exhaust temperature, and CO and oxygen 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, partial operational use, 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 where more than 50 percent run time of control is claimed. Glycol reboiler combustion claiming 50 percent or less run time for control is only required to do the basic monitoring for the 90 percent destruction efficiency level control.

Adopted subsection (m) Table 9 clarifies LDAR allowances and requirements, for fugitive monitoring and control claims. Compliance with this table is only required where a company wants to claim the reduction credits from an LDAR program reducing the basic leak rate potential estimates from the oil and gas factors. The table is separated into five basic sections, General, Exceptions, basic mandatory Requirements and allowances, and requirements and allowances if Enhanced LDAR Monitoring Options are claimed, and allowances for Instrument Monitoring Frequency Adjustments.

The General section covers the basic application of the subsection (m) Table 9 and clarifies that the records and monitoring in subsection (m) Tables 7 and 8 are connected. Operators should not assume this table is all encompassing for all state and federal LDAR rules. While it is currently very consistent with all other rules, those rules may change and there may be elements that are slightly more or less stringent.

The commission does not expect direct instrument monitoring of emissions unless a voluntary LDAR program is selected. Applicants can conservatively estimate the number and type of fugitive components by use of sister sites, blueprints, or similar facilities, etc., for preconstruction and follow up with an actual count after construction. If the actual count determines that the preconstruction estimate was too low or inaccurate, then a revised estimate should be submitted. Only when a voluntary LDAR program is selected is a fugitive components monitoring list required to be kept. Exceptions help clarify where the commission does and does not expect accounting and direct instrument monitoring of emissions from fugitive components, which should be helpful regardless of whether an LDAR control program is claimed. There is no expectation to account for emissions associated with nitrogen lines, noncontact steam lines, flexible plastic tubing equal to or less than 0.5 inches in diameter, unless it is subject to monitoring by other state or federal regulations, components operating under a vacuum of at least 0.725 psi below ambient pressure, lines where the VOC has an aggregate partial pressure of less than 0.002 psia at 68 degrees F, lines with only inert gases, CO_2, water, methane, ethane or Freon. All other components are expected to be accounted for emissions. The mass fraction of the relevant contaminants, VOC, BTEX and H_2S contained by the components may is be applied to determine the emission rate. Method 21 instrument monitoring at the appropriate leak definition chosen is not mandated to be applicable to components in the following service: pipeline quality natural gas, where the VOC aggregate partial pressure or vapor pressure is less than 0.044 psia at 68 degrees F or at maximum process operating temperature, for waste water lines containing less than 1 percent VOC by weight and operated at equal to or less than1 psig, for cooling water line components and for CO_2 lines after VOC is removed. This is referred to as Dry Gas lines in 40 CFR Part 60, Subpart KKK, and defined as a stream having a VOC weight percentage less than 4percent; a weighted average ESL of the combined VOC stream is greater than 3,500 $\mu g/m^3$; and total uncontrolled emissions for all such sources is less than1 tpy at any OGS. The table provides the calculation for this last exception. Note that these instrument monitoring exceptions are for the basic mandatory instrument monitoring in the Requirements portion of subsection (m) Table 9. A company may monitor any components where the instrument is capable of detecting a leak and claim reduction credit, per the Enhanced LDAR Monitoring Options. This is especially pertinent to the oil and gas industry where natural gas, methane and ethane, is commonly present, not required for this rule to be accounted, but it can be effectively detected with the instrument monitoring. Where sufficient methane and ethane are present in a heavy oil line where the VOC aggregate vapor pressure is less than 0.044 psia at concentrations sufficient to be detected as a leak by the instrument, credit for monitoring these components can be claimed.

The basic LDAR requirements must be complied with when claiming the reduction credit at a site. The following requirements are standard logical elements of good engineering practice and design and have been applied by the commission for many years. Proper design standards must be applied as applicable to new and reworked piping including American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Where technically feasible, new and reworked components may be screened for leaks with a soap bubble test within eight hours of being returned to service in lieu of instrument testing. Note that this soap bubble test is a unique allowance for the oil and gas PBR due to potential remoteness of the sites involved. Adjustments shall be made as necessary to obtain leak-free performance. Components shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. The routine physical inspection walk through with the proper design and construction work check, garner a 30 percent reduction credit in for emissions credit. This is applied to all fugitive components that are not monitored with an EPA Method 21 instrument.

Open-ended lines are required to be capped, plugged or have a second valve except during sampling or maintenance. This eliminates the expectation to estimate emissions from open ended lines and valves with a 100 percent reduction credit. This does not apply to safety relief valves which are assumed to have potential fugitive emissions and are monitored as appropriate. The requirement also addresses the logical need to create open ended lines when pulling equipment for maintenance. A 72- hour exception for maintenance activities is accepted and the vast majority of maintenance is expected to be completed in that time frame with the lines going back to normal. In the event of unusually long-term maintenance effort the open ended line should be capped or it needs to be monitored to ensure no leaks are occurring. Leaking open ended lines need to be fixed within 24 hours. Note these actions maintain the assumption of no relevant emissions from open ended lines.

Actual basic instrument monitoring is applied to the most common high potential leak sources quarterly with an instrument leak definition of 10,000 ppmv using EPA Method 21. If any component is noted to be leaking by sight, sound or smell, it must be taken care of or tagged and repaired according to the rule schedule in subsection (e)(5)(B).Table 9. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored, and are assumed not to have fugitive emissions. Valves that are difficult or dangerous to monitor may be accepted to be monitored annually or when safe, but reduction credit except for the 30 percent noted above should not be claimed for these components. Relief valves equipped with rupture discs are assumed to be 100 percent controlled but, a pressure-sensing device must be installed between the relief valve and rupture disc to monitor disc integrity and be checked weekly. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown. This shutdown does not need to be scheduled or planned, just the next shutdown that occurs. A record of the emission calculation showing that it would release more emissions to shut down than the leak is emitting is required to be kept. All pump, compressor, and agitator seals shall be monitored quarterly with an approved gas analyzer or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with automatic seal failure detection and alarm system need not be instrument monitored. Seal systems that prevent emissions may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure or seals degassing to vent control systems kept in good working order. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored. The agency is also allowing the use of the Alternative Work Practice in 40 CFR §60.18(g) - (i). All components are subject to leak checking when using the alternative work practice. Components subject to routine instrument monitoring with an approved gas analyzer or the alternative work practice under this leak definition my claim a 75 percent emission reduction credit when evaluating controlled fugitive emission estimates. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. Instrument monitoring and the credit should not be applied to components where the gas saturation concentration of the fluid contained would be below the leak definition.

Enhanced LDAR monitoring options may be claimed where component groups are subject to instrument monitoring where not normally required in the basic program above or when lower leak definitions are applied. Flanges and connectors could be subject to instrument monitoring along with the pumps and valves at the standard 10,000 ppmv leak definition quarterly and garner the 75 percent reduction credit. A company could elect to apply BACT level monitoring at their site applying a 2,000 ppmv leak definition to pump, compressor, and agitator seals when instrument monitoring using EPA Method 21 quarterly. This level allows an 85 percent reduction credit for the pumps, compressors, and agitator seals. A leak definition of 500 ppmv may be applied to any component groups, and OGS using this lower leak definition for valves, flanges or connectors may apply a 97 percent emission reduction credit; pumps may apply a 93 percent emission reduction credit; and compressor, agitator seals and other component groups may apply a 95 percent emission reduction credit for quarterly monitoring of those components. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. The component groups where lower leak definitions are applied need to be clearly identified in the records in subsection (m) Table 8, and monitored with correctly calibrated instrument per subsection (m) Table 7. The leak repair time frames and tagging requirements of subsection (e)(5)(B) of course continue to apply.

The PBR does allow, in the Instrument Monitoring Frequency Adjustments part of subsection (m), Table 9, the use of less frequent valve monitoring for valves when the leak rate is low. For a reduction in monitoring frequency, after completion of the required quarterly inspections for a period of at least 2 years, the operator of the OGS facility may change the monitoring schedule as follows: After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0 percent, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. Additionally, after five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0 percent, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. If the owner or operator is using the Alternative Work Practice in 40 CFR §60.18(g) - (i), the alternative frequencies specified in this standard permit PBR are not allowed. The PBR also allows for an early unit shut down or other appropriate action at the discretion of the commission or designated representative based upon the number and severity of tagged leaks awaiting shutdown.

Some of the records may already be compiled and kept in various formats for other regulatory agencies. If there is another record that shows the same information needed to demonstrate compliance with the PBR, that record will be sufficient. The commission does not want to make any duplicative requests for creation of information already being required for any other purposes.

Subsection (k) outlines requirements for establishing site-specific emission limits based on one or more standardized impacts evaluation techniques. For the proposal, the commission had included in subsection (k)(1) a basic precept for all air permitting emission quantifications, that estimates be based on representative, worst-case operations and planned MSS activities. For the adoption, the commission has moved the expectations for worst-case emission estimations to subsections (g) and (h). In response to comments, the commission notes that the applicant may choose to use various impacts evaluation methods for the same registration, depending on the project and registration's emissions of any particular air contaminant. For example for a project installing a new engine, NO_2 NAAQS compliance may be demonstrated using SCREEN modeling, while formaldehyde and SO_2 compliance with ESL concentrations may be demonstrated using the impacts tables. The commission has also added subsection (k)(1)(A) and (B). For subsection (k)(1)(A), ambient air standard requirements have been moved from subsection (b)(6) with grammatical changes. The commission has also added specifics on the distances relevant for each PBR Level, consistent with the distances used to establish the limits in subsections (g) and (h). For subsection (k)(1)(B), ESL requirements have been moved from subsection (b)(6) with grammatical changes. The commission has also added specifics on the distances relevant for each PBR Level, consistent with the distances used to establish the limits in subsections (g) and (h).

Subsection (k)(2) explains what distance measurements are needed. To alleviate any confusion, it is specifically stated that the distances needed are for each facility or group of facilities is the shortest distance from any emission point to the nearest receptor or nearest property line, depending on whether the compliance demonstration is for an ESL or an ambient air standard. For adoption, the commission has made one small grammatical change. The "and" between state and federal in subsection (k)(2)(B) has been changed to "or."

The commission has adopted subsection (k)(3) to list the exemptions from completing a detailed contaminant review. Adopted subsection (k)(3)(A) exempts projects with no receptor within 1/4 or 1/2 mile from any ESL evaluation. Based on comments, the commission has added this exclusion, agreeing that if no receptor could be impacted in close proximity and since the emission caps for speciated VOCs are based on 1/4 mile and 1/2 mile distances to receptors, respectively for Levels 1 and 2 of this section, there is nothing gained from performing this impacts evaluation. Adopted subsection (k)(3)(B) exempts projects with no property boundary within 1/4 and 1/2 mile from any state or federal ambient air standards evaluation. Based on comments, the commission has added this exclusion, agreeing that if no property line is in close proximity and since the emission caps were set to demonstrate protection of the standards at

1/4 mile and 1/2 mile distances to property lines, respectively for Levels 1 and 2 of this section, there is nothing gained from performing this impacts evaluation. Adopted subsection (k)(3)(B) also exempts projects with no property boundary within 1/4 and 1/2 mile from any state or federal ambient air standards evaluation. Based on comments, the commission has added this exclusion. The commission agrees that if no property line is in close proximity and since the emission caps were set to demonstrate protection of the standards and are based on 1/4 mile and 1/2 mile respectively for Levels 1 and 2 of this section, there is nothing gained from performing this impacts evaluation.

For adoption, subsection (k)(3)(C) has been moved from subsection (k)(3)(B). Based on proposal comments, subsection (k)(3)(C) has been clarified to explain that the total quantity of emissions for the project must be less than the listed rates in order for no further demonstration for a contaminant to be required. Using this basis is the most appropriate because this evaluation should account for all sources related to the project which has triggered the section. This evaluation is consistent with the other impact exception. The word "any" is also added to clarify that if any contaminant total emission rates are below the listed rates, the demonstration is not required for that contaminant. This means that demonstration could be required for one particular contaminant, but not for another.

The values used for the exemptions in subsection (k)(3)(C) were developed from the most appropriate and most stringent modeling results in subsection (m) at the closest distance of 50 feet. If emissions are less than these values, compliance with all ambient air standards and ESLs will be met; therefore, requiring an analysis by applicants would be redundant and unnecessary. To aid in this review, pollutant specific modeling result tables were created from the generic modeling results. For each pollutant, the most stringent of either an ESL or an ambient air standard expressed as a concentration was divided by the generic modeling results, which are in units of ($\mu g/m^3$)/(lb/hr) to obtain a table of emission rates (lb/hr). The value for NO_X was based on the less than 250 hp engine table, the new hourly NAAQS, and the shortest stack height, or 4 lb/hr. The value for H_2S was based on the fugitive column of subsection (m), Table 2 at 50 feet and was 0.025 lb/hr. The value for SO_2 was based on the 8-foot height smallest engine type of subsection (m), Table 5A at 50 feet and was 2 lb/hr. The value for benzene was based on the fugitive column of subsection (m), 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 0.039 lb/hr.

Subsection (k)(4), which was subsection (k)(3)(C) in the proposal, discusses what is required for evaluation of emissions. In subsection (k)(4)(A), the optional method of assuming all VOCs consistent with the most restrictive ESL under worst-case dispersion and closest distance to a receptor has been deleted based on comments stating that this option is too restrictive to be a meaningful tool for a project or registration. Instead, subsection (k)(4)(A) is adopted with NO_2 to NO_X ratios updated based on engine testing as provided by companies, vendors, or manufacturers. The typical NO_2 to NO_X ratio from engine sampling commonly seen by the commission ranges from less than5 percent to 40 percent. The annual NO_2 NAAQS has an EPA-approved modeling default ratio of 0.75. The current one-hour NO_2 NAAQS has an interim modeling default ratio of 0.75 as well. That means that 75 percent of the NO_X emitted is assumed to be NO_2 and modeled as such. The commission believes using the 0.75 ratio is too conservative for the one-hour standard given several important factors. First, actual sampling data received in response to comments shows that the percentage of NO_X that is NO_2 immediately prior to release into the atmosphere ranges from 2 to 20 percent with the majority less than 15 percent for 4-stroke rich-burn and 4-stroke lean-burn engines. This is well below the modeling default ratio of 0.75. Secondly, NO is oxidized to NO_2 in the atmosphere by reaction with other molecules (ozone, etc.). This requires time, but the plume also is being dispersed the farther from the stack it travels. So, while the ratio of NO_2 to total NO_X for a given section of the plume may be slowly increasing to an equilibrium ratio of 0.75, the total NO_X concentration is dropping as distance from the stack increases. The maximum ground level impact of NO_2 occurs where the product of the NO_2/ NO_X ratio times the total NO_X concentration is the greatest at any given location. Given how quickly ground level concentrations usually drop as distance increases and the time needed to reach equilibrium, this maximum NO_2 impact tends to be relatively close to the emission point. A previous compressor station study by the commission showed that the NO_2/ NO_X ratio appeared to max out at around 14 percent in the area downwind of the studied site where maximum NO_X concentrations were expected. Upon review of this information, the commission has determined it is reasonable to allow a lower NO_2/ NO_X ratio. Given the submitted sampling data and previous commission experience, a ratio of 20 percent is appropriate for 4-stroke engines. Several 2-stroke lean-burn engines in the submitted data set emitted about 50 percent NO_2 and the commission believes the ratio of 50 percent is appropriate for 2-stroke engines. The commission does not anticipate allowing lower values than these due to the complexity of validating site specific values. Sites wishing to use a lower ratio may have to perform ambient air monitoring for NO_2 at the predicted location of the maximum ground level impact of NO_2.

In subsection (k)(4)(B), it states that the maximum predicted concentration or rate must not exceed a state or federal ambient air standard or ESL. The scope of the analysis has been moved to subsection (k)(5). The last sentence of this subparagraph was redundant with the first sentence, and therefore was deleted.

Subsection (k)(5) discusses what is required for ESL and ambient air standards reviews in subsection (k)(5)(A) and (B), respectively. Subsection (k)(5)(A)(i) states that if a project's air contaminant maximum predicted concentrations are equal to or less than 10 percent of the appropriate ESL, no further review is required. Based on the "Modeling and Effects Review Applicability: How to Determine the Scope of Modeling and Effects Review for Air Permits" guidance document last revised in July 2009 by the commission, the commission has added options to evaluate only the emissions from the project, and not all sources within 1/4 mile of the project. This option is based on several comments and this approach is consistent with minor source review permitting procedures which have been followed by the Air Permits Division since 1993. This approach provides a process to protect public health and welfare and effectively manage permitting and agency support staff resources. The thresholds for health effects reviews are consistent with this guidance (10 percent of an ESL). Subsection (k)(5)(A)(ii) states if the combination of multiple project increases corresponding air contaminant maximum predicted concentrations over a 60-month period are equal to or less than 25 percent of the appropriate ESL, no further review is required. The commission has established a maximum amount of cumulative increases over time (25 percent) to ensure that emissions "creep" does not occur over multiple projects without a more comprehensive review being performed. The 60-month period is consistent with federal operating permit maximum recordkeeping duration. Subsection (k)(5)(A)(iii) states that in all other cases, all facility emissions, regardless of authorization type, located within 1/4 mile of a project requiring registration under this section shall be evaluated. The requirements for additional facilities to be included in the impacts analysis moved from subsection (b)(6).

Subsection (k)(5)(B)(i) states that if a project's air contaminant maximum predicted concentrations are equal to or less than the SIL (also known as *de minimis* impact), no further review is required. Based on recent implementation guidance from EPA regarding the new NO_2 and SO_2 NAAQS, the commission is using the significance impact level (SIL), more commonly known in Texas as *de minimis* impact level, to allow evaluation of the project only. This option is based on several comments and this approach is consistent with major and minor source review permitting procedures followed by the Air Permits Division. This approach provides a process to protect public health and welfare and effectively manage permitting and agency support staff resources. The current thresholds for ambient air standards reviews are consistent with EPA guidance. This exception is consistent with minor and major preconstruction permit reviews. Subsection (k)(5)(B)(ii) states that in all other cases, all facility emissions, regardless of authorization type, located within 1/4 mile of a project requiring registration under this section shall be evaluated. The requirements for additional facilities to be included in the impacts analysis moved from subsection (b)(6).

Finally, in subsection (k)(6), modified from subsection (k)(4), the commission adopts three methods for demonstrating protectiveness. The first method is to use tables developed from generic impacts modeling performed by the commission. Based on comments, the commission has expanded the table distances to over 1 mile to allow for more flexibility based on actual locations throughout Texas. The commission has also expanded the tables for engines based on more specific and representative dispersion characteristics, and renumbered to Table 5A-F in subsection (m). The Tables have also been reorganized as follows: Table 2. Generic Modeling Results for Fugitives & Process Vents (no change); Table 3. Generic Modeling Results for Flares; Table 4. Generic Modeling Results for Blowdowns & Gas Pipeline Purging; Table 5A Generic Modeling Results for Engines and Turbines Less than or Equal to 250 hp; Table 5B Generic Modeling Results for Engines and Turbines More than 250 hp to Less than or Equal to 500 hp; Table 5C Generic Modeling Results for Engines and Turbines More than 500 hp to Less than or Equal to 1,000 hp; Table 5D Generic Modeling Results for Engines and Turbines More than 1000 hp to Less than or Equal to 1,500 hp; Table 5E Generic Modeling Results for Engines and Turbines More than 1,500 hp to Less than or Equal to 2,000 hp; and Table 5F Generic Modeling Results for Engines and Turbines Greater than 2,000 hp. The commission limits the evaluation in subsection (k) to 5,500 feet based on consideration of distance limits for contiguous properties and operationally related facilities; the highly conservative nature of the assumptions used to develop 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 5,500 feet.

Using the generic impacts modeling tables developed by the commission is considered the simplest approach to this evaluation. 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. The other two methods are screening modeling and refined dispersion modeling.

Subsection (k)(6)(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 the one described below.

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

For source options in the screen model, only point sources, pseudo-point sources, and flares are applicable to represent emission sources. If the emission sources cannot be represented by one of the source types, then this method cannot be used. The point source parameters shall include the following: emission rate in grams per second (g/s); stack height in meters (m); stack inside diameter in meters (m); stack gas exit velocity m/s or flow rate in cubic feet per minute or meters per second (ft^3/min or m^3/s); and stack gas temperature in Kelvin (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 m/s; stack exit diameter = 0.001 m; 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 at this time.

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 or equal to the NAAQS. The following steps must be followed when conducting the analysis to show compliance with the state standards for net ground-level concentrations in 30 TAC Chapter 112 or ESLs: 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 or ESLs 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 contaminant. Compliance with the state property line standards and ESL is demonstrated if the maximum predicted site-wide concentration is less than or equal to the state property line standard or ESL.

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 worst-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; Π = 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 g/s. 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 commission 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.

Subsection (k)(6)(C) includes a refined dispersion modeling alternative based on the Industrial Source Complex model. The OGS would follow a modeling protocol provided by the commission to conduct a modeling analysis that demonstrated acceptable emission from the site. The protocol and associated guidance would be included in an oil and gas guidance document available via the agency website. The protocol would be followed exactly and there would be no opportunity to modify the protocol on a case-by-case basis. However, the commission could modify the modeling protocol and guidance to resolve technical issues, clarify instructions, or allow the use of other refined dispersion models. Since this is a standardized approach, it is appropriate to allow OGS to use these mechanisms to demonstrate protectiveness.

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

Only point sources, pseudo-point sources, and flares are applicable to represent emission sources. If the emission sources cannot be represented by one of the source types, then this method cannot be used. Point source parameters shall meet the following: emission rate (g/s); stack height (m); stack inside diameter (m); stack gas exit velocity (m/s) or flow rate (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 at this time. 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 Air Permits Division Form PI-1, Table 1(a) available through the commissions Web pages 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 which must be used to compare against the applicable ESL, NAAQS, or state ambient air standard; the use of any other concentration rank other than the maximum (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 or equal to the NAAQS. The following steps must be followed when conducting the analysis to show compliance with the state standards for net ground-level concentrations in 30 TAC Chapter 112 and ESLs: 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 and ESLs 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 contaminant; and compliance with the state property line standard and ESL is demonstrated if the maximum predicted site-wide concentration is less than or equal to the state property line standard or ESL. Once the modeling exercise is complete, the results should be summarized in a modeling report. The modeling report should be sent to the commission 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.

The commission adopts subsection (l) to cover existing, unchanged facilities at OGS. Since the changes to this section under §106.352 are going to affect oil and gas operation based on a phase approach, Barnett Shale area first, followed by the rest of the state, this section will cover those facilities that are not effected on April 1, 2011. The addition of this subsection also covers those existing, unchanged facilities that are not subject to the rule change as describe above. This subsection will continue to be the authorization mechanism for facilities that are unchanged, but at a site which has undergone new or modified construction on some facilities.

Subsection (m) was due to the inclusion of the previous requirements of §106.352 in subsection (l). The introductory sentence is also revised as this subsection contains more tables than those used for the protectiveness review as required in subsection (k).

Subsection (m) 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; (no change); Table 3. Generic Modeling Results for Flares; Table 4. Generic Modeling Results for Blowdowns & Gas Pipeline Purging; Table 5A Generic Modeling Results for Engines and Turbines Less than or equal to 250 hp; Table 5B Generic Modeling Results for Engines and Turbines More than 250 hp to Less than or Equal to 500 hp; Table 5C Generic Modeling Results for Engines and Turbines More than 500 hp to Less than or Equal to 1,000 hp; Table 4 hp; Table 5D Generic Modeling Results for Engines and Turbines More than 1,000 hp to Less than or Equal to 1,500 hp; Table 5E Generic Modeling Results for Engines and Turbines More than 1,500 hp to Less than or Equal to 2000 hp; Table

5F Generic Modeling Results for Engines and Turbines Greater Than 2,000 hp; Table 6 Engine and Turbine Emission and Operational Standards; Table 7 Sampling and Demonstrations of Compliance; Table 8 Monitoring and Records Demonstrations; and Table 9 Leak Detection and Repair Programs.

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 (µg/m^3); and G is the value from the Generic Emissions Tables at the emission point's release height and distance to property line ((µg/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 (µg/m^3); and G is the value from the Generic Emissions Tables at the emission point's release height and distance to property line ((µg/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, OGS may use a weighted fraction method. The 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) +...Repair (LDAR) Control Program Table.

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 (m), 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 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 percent 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.

Table 7 in subsection (m), Sampling and Demonstrations of Compliance, gives the specifics of what sampling is required and what demonstrations of compliances are expected. NELAC is a requirement of the commission, and for any testing that is performed that the commission has an accreditation for, that test must be done by a NELAC accredited Lab. Laboratory analyses are needed in order to estimate emissions and site specific analysis are the most accurate for estimating emissions. However, the commission recognizes that it may be impractical to have site specific analysis for every site. Therefore, the commission is allowing for representative sampling. The commission will publish guidance on what is representative analysis that has been through a public comment period. This will allow for the guidance to be updated as more relevant information in available. There are several types of lab analysis available to obtain the required information needed for estimating emissions. They include but are not limited to GC, Tutweiler, stain tube analysis, and sales oil/condensate reports. These records will document the following: H_2S content; flow rate; heat content; or other characteristic including, but not limited to: American Petroleum Institute gravity and RVP; sales oil throughput; or condensate throughput.

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: 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.

Table 8 in subsection (m), Monitoring and Recordkeeping, this table shows what the requirements for monitoring and recordkeeping are for different facilities at an OGS. The site inlet and outlet volumes, liquid productions, H_2S content, truckload out are needed in order to demonstrate compliance with the rules, and any changes that are made to the site that might increase emissions. This includes the minor changes that only require recordkeeping and incorporation at the next amendment. This also pertains to the site layout, equipment summary, and process diagram. The plot plan is needed since the first registration sets the boundaries for demonstrating impacts analysis. The current emissions calculations for the process at the site need to be kept in order to demonstrate compliance with the rule. This has always been the requirement of §106.8. This will let the owner/operator know whether they are in compliance with the limits of the PBR. Additionally, it will allow the owner/operator to keep track of the minor changes allowed in this section and be aware when other permitting options are needed.

FINAL REGULATORY IMPACT ANALYSIS DETERMINATION

The commission reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225 and determined that the 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 public 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 public 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 rulemaking does not constitute a major environmental rule, even if it did, a regulatory impact analysis would not be required because the rulemaking does not meet any of the four applicability criteria for requiring a regulatory impact analysis for a major environmental rule. Texas Government Code, §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 rulemaking does not meet any of the four applicability criteria listed in Texas Government Code, §2001.0225 because: 1) the rulemaking is designed to meet, not exceed the relevant standard set by federal law; 2) the rulemaking does not exceed an express requirement of state law; 3) no contract or delegation agreement covers the topic that is the subject of this rulemaking; and 4) the 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 rulemaking is to repeal the current requirements of §106.352 and implement a new set of requirements for the PBR. The new PBR requirements provide an updated, comprehensive, and protective authorization for many common oil and gas facilities in Texas. The PBR includes 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 PBR specifically addresses 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.

TAKINGS IMPACT ASSESSMENT

The commission completed a takings impact assessment for this rulemaking action under Texas Government Code, §2007.043. The specific intent of the rulemaking is to repeal the current requirements of §106.352 and implement a new set of requirements for the PBR. 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 rulemaking and found it is 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 rulemaking for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council and determined that the 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 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 PBR and standard permit were developed to provide an updated, comprehensive and protective authorization for common OGS in Texas. The PBR and standard permit address the appropriateness of multiple authorizations at one contiguous property. One of the limitations of the 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.

PUBLIC COMMENT

A public hearing was held in Austin on September 14, 2010. 222 commenters submitted comments during the public comment period which closed on October 1, 2010. The commenters included the following: Representative Lon Burnam, Representative James Keffer, Senator Wendy Davis, Senator Robert Nichols, Senator Kel Seliger, Representative Warren Chism, Representative Wayne Christian, Representative Tom Craddick, Representative Kelly Hancock, Representative Rick Hardcastle, Representative Ken Legler, Representative Randy Weber, City of Fort Worth, Akzo Noble, Anadarko Petroleum Corporation (Anadarko), Argyle-Bartonville Communities Alliance (ABCA), Bart May Trucking, British Petroleum America Production Company (BP), Bridgeport Chamber of Commerce, Christian & White Properties, Cirrus Environmental Corporation (Cirrus), ConocoPhillips, Devon Energy Corporation (Devon), Environmental Defense Fund (EDF), El Paso Corporation (El Paso), EnCana Oil & Gas USA Inc. (Encana), United States Environmental Protection Agency, Region 6 (EPA), Energy Transfer Company (ETC), ERM, ExTerran, ExxonMobil Production (ExxonMobil), Fasken Oil and Ranch, Ltd. (Fasken), Fort Worth Crushed Stone, LLC, Fountain Quail Water Management (Ft Quail), Gas Processors Association (GPA), Harris County Public Health & Environmental Services (HCPHES), Hy-Bon, Jerry Lang Combustion Consulting (JLCC), Jones-Blair Paint Co. (JBP), Kinder Morgan, Inc. (Kinder Morgan), Lone Star Chapter of the Sierra Club (Sierra Club), M.E. Operating and Services, Inc., Markwest Energy Partners, Noble Energy Inc. (Noble), Nord On Corporation, NorTex, Old Town Neighborhood Association, Parrish Field Services, Permian Basin Petroleum Association (PBPA), Pioneer Natural Resources USA, Inc. (Pioneer), P_S^TORD OPS^T Corporation, Shell Global Solutions (Shell), Shell Exploration & Production Company (SWEPI), Texas Alliance of Energy Producers (TAEP), Targa Resources Partners LP (Targa), Texas Pipeline Association (TPA), Texans for Responsible and Accountable Energy Development (TRAED), Texas Oil and Gas Association (TXOGA), Earthworks Texas Oil and Gas Accountability Project, Texas Independent Producers & Royalty Owners Association (TIPRO), Texas Pipeline Association (TPA), Mayor Calvin Tillman of DISH, Weisman Engineering and 124 various individuals.

RESPONSE TO COMMENTS

MAJOR ENVIRONMENTAL RULE

TXOGA, Anadarko, Noble, ExxonMobil, TPA, PBPA, and GPA commented that the commission failed to meet the requirements of Texas Government Code, §2001.0225 by not producing a regulatory impacts analysis determination as would be required for 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 public 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." For rules that are subject to Texas Government Code, §2001.0225, the preamble is required to contain a draft impact analysis that must, among other things: (i) describe the benefits and costs anticipated from implementation of the rule in as quantitative a manner as feasible, and (ii) describe reasonable alternative methods for achieving the purpose of the rule that were considered by the agency and provide the reasons for rejecting those alternatives in favor of the adopted rule. In addition, the commission must develop a final regulatory analysis that finds that, "compared to the alternative proposals considered and rejected, the rule will result in the best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered."

Devon agreed with TXOGA's and TIPRO's comments that the proposed PBR exceeds federal regulatory requirements in several respects. As such, Devon stated TCEQ's proposed PBR is a major environmental rule under Texas Government Code, §2001.0225 and that the TCEQ has not complied with the statutory requirements in Texas Government Code, §2001.0225 for proposing major environmental rules.

PBPA further stated that in this new rule TCEQ is administering federal law by updating/revising its State Implementation Plan of the Federal Air Quality Act. In reviewing the proposed new TCEQ rule it is evident that the agency has not conducted a careful and detailed economic cost/benefit analysis of the proposed new measures commensurate with their scope and certain economic burden. PBPA also stated that the TCEQ claims that the new rule does not constitute a "major environmental rule" because the commission anticipates that the economic impacts would be small. TCEQ thus claims that it is not required to complete a "regulatory impact analysis" prior to proposing the new rule. However, in our view the TCEQ did not give serious consideration to the economic costs and consequences of this proposed new rule by the fact that the word "economic" was found three times and the word control (and its derivatives) was found 330 times throughout the TCEQ documents (Chapters 106 and 116). While the word "cost" was used more frequently, there was clearly no attempt to aggregate total costs to industry, the consumer or taxpayers in any useful or meaningful way. Nor were the negative effects of additional, imposed costs named in terms of their effects on production economics or recoverable reserve. We therefore submit that the proposed new rule is a "major environmental rule" and that TCEQ must abide by THSC, §2001.0225 and conduct such an economic analysis before the final version of the rule can be proposed. We strongly recommend that TCEQ solicit the input of oil and gas industry representatives during the analysis, as only they have the expertise and first-hand knowledge necessary for the production of a valid and meaningful economic study.

PBPA disagrees that the proposed regulations are not a major environmental rule. The economic effects will be large, and PBPA requests the commission to further cost analysis. PBPA applauds TCEQ's efforts in refining emission estimation methodologies. TCEQ should collaborate with industry environmental engineers and scientists to develop emission estimate methodologies which are robust and efficient. The proposed limits on VOCs, H_2S, and SO_2 go beyond what is required in other states.

Common Issues related to Production Value vs. Cost of Protectiveness.

Specifically, commenters stated that TCEQ has not met the requirement under Texas Government Code, §2001.0225 to perform a cost/benefit analysis of various alternatives for

TCEQ's overall stated goal of "ensuring that authorizations for OGS are improved for enforceability, updated based on current scientific information, and to properly regulate all operations" and to "increase protection of the environment and reduce risk to public health. Rather, TCEQ has focused its efforts on imposing new and onerous requirements on OGS without adequately demonstrating that the resultant emissions reductions will provide any meaningful beneficial improvements in protectiveness at economic costs not materially greater than the costs of alternative regulatory methods that could have been considered.

The commenters stated that the TCEQ concludes in the preamble to the proposed rulemakings are not "major environmental rules" subject to a regulatory analysis required by Texas Government Code, §2001.0225. TXOGA disagrees. In particular, TXOGA strongly disagrees with the commission's conclusion that the proposed rulemakings will not 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. The commission states in the preamble that the proposed rulemakings would require approximately 9,000 OGS to submit either a Level 1 or a Level 2 authorization each year, and that an additional 500 OGS currently authorized by the existing PBR would need to obtain authorization under the proposed standard permit.

The commenters also stated that they do not understand how TCEQ can suggest that the PBR and the standard permit do not affect in a material way the oil and gas sector of the economy or productivity and jobs. They estimate that the rules will cost operators of OGS: 1) Permitting costs for existing facilities of over $260 million when the requirements of the rules become effective; 2) Over $95 million in additional, annual costs for additional employees to comply with the new requirements of the rules; 3) Registration costs of over $191 million for existing, unmodified OGS in 2013; and 4) Over $277 million in lost production from wells (a cost of over $1,750 per well) which will be shut down sooner due to higher production costs or wells not drilled at all. These costs are based on the calculations and conservative assumptions set out in line items in attachments to their comments. The costs noted above and in other specific details are indirect costs, and do not include direct costs such as the costs of controls and testing by third parties. Since the PBR and standard permit would materially affect the oil and gas sector of the economy, they fit under the definition of a major environmental rule.

PBPA commented that existing Texas law and TCEQ rules are sufficient to protect air quality in the Permian Basin and other areas, which has been steadily improving over the past many years. The PBPA believes that industry would benefit from a better partnership with TCEQ were they to focus on developing best management practices which have both an economic payout and result in air quality improvement. Any new regulatory requirements that impose additional cost and/or logistical burdens should pay for themselves so that their benefits would be self-evident and their implementation self-sustaining. An economic payback of 18 to 24 months would be a reasonable threshold for an environmental type project, and would weed out the locations with low volumes and high pipeline pressures (or no pipeline). Pioneer Natural Resources stated that the rules will be onerous to implement, will have a profound effect on the oil and gas industry in Texas, will discourage addition of emission reduction equipment, and will yield minimal results to air quality Improvements.

PBPA estimates the capital cost of installing a small, smokeless combustor for a small site may range from $10,000 to $20,000. Annual operating costs may be assumed to be $1,000 per year when maintenance and personnel costs are considered. The estimated capital cost of installing a VRU may range from $25,000 to $100,000 per facility. Annual operating costs may be estimated at $2,500 per year when maintenance and personnel costs are considered. Controls will need to be monitored for effectiveness on an annual basis, to include measurement of throughput and emission control effectiveness. Tank painting costs could range upwards of $10,000 per tank or more. They also state that there is no cap on what level of emissions controls TCEQ may deem adequate.

Devon commented that, based on their understanding and interpretation of the rules, they estimate compliance costs in the range of $30 - $40 million each year with minimal impact on air emissions in Texas. "Section 382.011 of the TCAA directs the TCEQ to control air contaminants by "practical and economically feasible methods." As detailed in TXOGA's and TIPRO's comments, the PBR and standard permit would impose a multitude of onerous and burdensome requirements on OGS that are neither practical nor economically feasible. For the foregoing reasons, TCEQ's PBR and standard permit would appear to be subject to challenge as arbitrary or unreasonable under TCAA, §382.032, Appeal of Commission Action." PBPA also commented that "the rule is so expansive and comprehensive in scope that PBPA believes it warrants an evaluation as to whether TCEQ has the legal authority to promulgate the new rule absent direct legislative approval. In other words, this new "rule" is more like a new "law," and new laws must be enacted by the state legislature and signed by the governor." Still further, Devon claims that "based on pre-construction authorizations being required for OGS with 10 tpy or greater of VOC, a significant number of OGS would be waiting for permits resulting in deferred production. Assuming half of Devon's annual PBR submittals would require pre-construction authorization, with an average waiting period of 15 days and using average

2009 oil and gas production from the Texas Railroad Commission with very conservative product pricing, the cost of lost or deferred production is estimated at $7 million per year."

ETC commented that they will be significantly affected by the rule and estimates that it may increase ETC operating costs by more than $16 million per year and impose additional capital costs of more than $55 million.

SWEPI commented that the rule will force operators to undertake actions which may be only marginally beneficial to people and the environment while coming at high costs. They submitted several comments or alternative measurement methodologies that can be less burdensome to the oil and gas production industry and at the same time achieve the same emission performance assurances.

In June 2010, the commission proposed a new PBR and standard permit for oil and gas facilities. As noted, one of the main goals of the proposals is to increase the protectiveness provided by these authorizations. In an attempt to reach that goal, the commission proposed some new requirements and has made some requirements stricter. The commission understands that the new PBR and standard permit will cause owners and operators to incur some costs. At first glance, the estimated costs laid out by industry appear daunting. Some estimates range as high as $750 million to implement the new rules statewide. Some commenters stated that the impact from the proposed PBR and standard permit will "adversely affect" the oil and gas industry "in a material way," and requires that the commission conduct a Regulatory Impacts Analysis. However, when one

puts those numbers into context, it is clear that any allegations that these costs will devastate the oil and gas industry are not supported by the facts.

The oil and gas industry reported a combined market value of produced crude oil, natural gas, and condensate of $61.905 billion for fiscal year 2010. This is only the product recovered and sent to market, and does not include product that could have been and was not recovered. In other words, the estimated costs that industry estimates will be incurred as a result of these new PBR and standard permit ($750 million) amount to less than 1.2 percent of the value of crude oil, natural gas, and condensate produced by the industry in fiscal year 2010. Furthermore, the cost estimates provided by industry are somewhat inflated and do not coincide with commission estimates. Commission staff has confirmed specific examples of industry overestimating the cost of compliance with the proposed authorizations. Finally, the controls required by the new PBR and standard permit will prevent millions of dollars of product from escaping into the environment and enhance the industry's bottom line. In fact, in many instances, the cost of the control will pay for itself and actually result in a net profit for owners and operators.

Production Value vs. Cost of Protectiveness.

The oil and gas industry is indisputably a major portion of the Texas economy, and the commission confirms its previous determination that the adoption of this rule will not affect this portion of the economy in a material way.

The ability of an industry to pay for environmental controls is not the deciding factor in the decision of whether a particular control will be implemented. The financial resources of an industry are, however, a legitimate standard to measure the "material effect" of an environmental proposal. Based on information concerning taxable revenue supplied by the industry to the Texas Comptroller's Office, the oil and gas industry reported a combined market value of produced crude oil, natural gas, and condensate of $61.905 billion for fiscal year 2010. TXOGA submitted estimated costs to the industry of the commission's proposed controls of $0.75 billion. These costs represent 1.2 percent of the industry's revenue within the state. This is a worst-case estimate for the industry based on estimated costs which the commission believes are inaccurately high.

Additionally, the oil and gas producers who submitted comments have a combined net profit nationwide of $65.15 billion. Using the TXOGA estimate of compliance costs, these rules will cost the producers slightly over 1 percent of their profit.

The commission is aware that many OGS are owned and operated by small companies or individuals, and that industry-wide cost calculations will not apply to each owner or operator equally. Information supplied by the Texas Railroad Commission indicates approximately 400,000 OGS are operating in Texas. Using the Texas Comptroller Office's figure for market value of crude oil, condensate, and natural gas, the commission obtains a figure of approximately $145,000 of marketable product per site. This amount does not include produced water, which

is either processed and sold as product or re-injected into the field. TXOGA submitted a total estimated cost of $4,000 for individual compliance costs per new site. The line items detailed in their estimate actually totaled $5,000, which is the figure used by the commission in this analysis. The $5,000 estimated cost of compliance is 3 percent of the marketable product value per site. As with the industry-wide calculation, the commission believes that the estimated costs supplied by TXOGA for individual site compliance are inaccurately high and do not consider that smaller sites will have lower compliance costs. These costs are also a worst-case estimate based on figures supplied by TXOGA. Those portions of the rule that TXOGA contends are the most expensive sampling, recordkeeping, and protectiveness determination apply only to new or modified sites.

The Estimated Costs of Compliance Are Too High.

The commission disputes the cost estimates submitted by TXOGA. The figures are high based on rule requirements in existence prior to this adoption and exemptions the commission has included for smaller businesses. An example is the permit fee of $450, which applies to companies with over 100 employees or over 6 million in annual gross receipts; small business are only required to pay a permit fee of $100.

Data Gathering.

Prior to this adoption, the commission required the following records to confirm compliance with §106.8: inlet separator analyses, stack testing and sampling on

engines, applicable manufacturer data and catalyst information, liquid and gas throughputs, plot plan or PID, component counts or rough estimate, emission calculations based on throughputs and PID, and flares and associated waste stream(s). The commission is not sure what activities the commenters are considering under the heading of "data gathering" or if this recordkeeping is included under consultant fees, but the listed records have been required since April 2002 and should not be associated with this rule.

Although the existing §106.352 does not explicitly outline the specific types of records companies should keep, the commission has always assumed that owners and operators of OGS had sufficient operating and maintenance plans in place, that are consistent with industry practices, which would maximize production of their site and minimize any associated emissions, maintenance needs, and downtime. Companies would inherently need specific information about their sites so that they can be designed and operated in such a way that will optimize the production of marketable product. It is crucial for a company to know what liquids and gases are being pulled to the surface, as well as the composition of the liquids and gases, so that appropriate measures can be taken to condition, treat, or compress gas, store and transport certain liquids, install additional piping components where needed, anticipate when maintenance activities might occur, etc. Furthermore, this site-specific information has been required as part of §106.8, which states that "records must be maintained and contain sufficient information to demonstrate compliance with all applicable general requirements of §106.4, as well as all applicable PBR conditions." The information required in

the adopted rule is not new, considering that existing sites should already have, and have been required to maintain since April 2002, documentation that verifies all requirements of §§106.4, 106.352, 106.492, and 106.512 have been met including emission estimations. Emissions would have been derived from the pertinent information outlined above.

Modeling.

The commenters estimate modeling as the second most expensive requirement. Modeling is not required, but is an option the commission included in the proposal at stakeholder request. Modeling costs are site-dependent based on equipment at the site and gas composition. Smaller, less complex sites should have lower modeling costs. Additionally, EPA provides free modeling applications. The commission also respectfully questions whether modeling would be conducted by a consultant and should be covered under the consultant fee.

Sampling.

The commenters estimate $500 as the expense for sampling at both new and existing sites. It is unclear if the sampling cost was from testing of engines or gas and liquid analyses needed for estimating emissions from production and gathering. Existing sites were previously under sampling requirements of §§106.4, 106.8, and 106.512 specifically, and no new additional sampling would be required under this rule for existing or new sites. There will be no new additional sampling requirements for new sites under §106.512. There may be some new sampling cost for new sites under the new rule. However, if there is a representative sample

available that meets the protocol for a representative analysis, there may be no new costs.

Consultant Fees.

The commenters estimate consultant fees at $3,000 for new sites and $700 for existing sites but are silent on the services to be provided by the consultant. In the commission's experience, the previous expense categories other than permit fees could and have been included in consultant services. The ePermits system for Air Permits was constructed for this rule, and this system is designed for the convenience of the permit holder and should take minimal time to employ. For example, the system recognizes existing companies in its system and will auto-populate appropriate cells with general information, which will only require the entry of data to verify new, site-specific, and contact information. The commission estimates this will require a maximum time of one hour to complete.

Summary.

The commission believes it is reasonable to consider these issues in calculating control costs as a result of adopting this rule. For new sites, the commission removes the line items for data gathering, modeling, and sampling, assuming that these services will be provided by a consultant. The commission is using $4,000 for the consultant fee. When added to the permit fee of $450, the total for a new site is $4,450 in total control expenses. This is 3 percent of the calculated revenue per site ($145,000) based on Texas Railroad Commission and Texas Comptroller Office figures for the number of OGS and product value.

For existing sites, the commission removes the line item for sampling which leaves the consultant fee of $700. This is 0.4 percent of the calculated revenue per site.

To estimate the cost of a PBR registration, the Small Business and Environmental Assistance Section asked Air EnviroMentors to provide quotes for preparing a registration package. Air EnviroMentors is a commission-maintained registry of environmental professionals who specialize in helping small businesses and local governments with compliance issues. The fee quotes are grouped based on a company submitting a PBR registration, the size of the consulting firm (solo practitioner, small firm, or medium firm), and the information needed to complete the registration package.

The categories for which quotes were provided include documentation only, registration with a site visit, registration with a site visit and samples, registration with a site visit but no samples, and the estimated total cost of registration. The costs discussed in the following paragraphs are from select Air EnviroMentors. The quotes include many of the same costs represented by TXOGA, including documentation, site visit costs, sampling, and modeling. The quotes for registration packages requiring minimal documentation and other data were lower than TXOGA's quotes, approximately $1,500 to $3,500. To prepare a registration including a site visit and sampling was quoted between $4,700 and $ 6,250, which is approximately the same as TXOGA's quotes. If the registration package included modeling the registration was quoted as costing $8,500 to

$13,500.

Although, the quotes combine all fees associated with preparing the registration package rather than listing each item individually, the cost ranges could be deduced from the different scenarios provided. The quotes included the following costs: a site visit ranged from $1,250 to $2,000, samples ranged from $1,200 to $2,000, and modeling ranged from $2,250 to $6,800. The commission would like to make clear that a site visit is not specifically required by the new PBR requirements. Companies and consultants may choose to conduct site reviews in the process of preparing a registration package. Companies may require site reviews for new sites and a site review may be needed for some companies to accurately represent the site process and to verify the installed equipment at the site. However, for existing sites, companies should have already been maintaining this information according to §106.8 since April 2002.

As previously stated, samples are needed in order to determine how to treat and handle the liquids and natural gas as well as a basis for determining the product composition being sold. However, even if one disregards the commission's previous discussion of industry versus commission estimated costs to prepare a complete PBR registration and assumes the high estimated registration costs, the total registration cost per site as a percentage of the total capital cost to construct a site ranges from 0.38 percent to 0.51 percent.

The commission is aware that costs will vary by site, but this is true for the

commission's and commenter's estimates. The commission has included this discussion to establish a reasonable range of control costs.

Cost of Drilling vs. Cost of Protectiveness.

Another useful measure of the relative costs of the adopted rules is a comparison to the cost of well drilling and initiation of production. Between 2004 and 2007, the average cost of drilling exploratory and development wells increased from $1.7 million to $3.9 million. This cost does not account for the lease equipment costs or the annual operating costs associated with a producing well. Based on United States Energy Information Administration (EIA) statistics from 2009, the cost of drilling and operating an oil or gas well in Texas ranged from $1.7 to $2.9 million, depending on the location of the well in Texas and the well depth. Individual companies maintain that drilling costs are proprietary in nature; public sources indicate that record oil prices and a limited number of supplies are driving up the cost to drill oil wells.

Although these drilling costs are based on national averages, oil and gas production in Texas accounts for nearly 30 percent of all production in the United States. Therefore, one could assume that the costs to drill in Texas would influence the national average. Nationwide, in 2009, the *Oil and Gas Journal* estimated that $162 billion was spent for oil and natural gas drilling and exploration alone. Another $31 billion was spent for production. Still further, an estimated $39 billion was spent on other energy costs (including refining, natural

gas and crude pipelines, and marketing).

While TXOGA contends that the new rule will result in increased costs to oil and natural gas companies, $5,000 per new project and $1,200 ($700 for consultants and $500 for emissions quantification) for existing site notification requirements, the impact of these costs should be put into perspective. If the cost to drill an oil and gas well in 2007 was $3.9 million (and that cost has likely risen), the incurred cost of $5,000 to permit a new project is only 0.13 percent of the total cost to drill. This does not factor in the additional $1.7 million per year to operate that same well. The incurred cost $1,200 for existing site notifications is only 0.03 percent of the cost needed to construct the existing site. Even considering that the well is 20 years old, constructed in 1990 when the average cost to drill was $531,300; today's cost of notification for that well is still only 0.22 percent of the total cost to drill.

Cost of Drilling vs. Cost of Protectiveness for Small Businesses.
Special attention was given to the potential impacts of the new PBR on small independent oil and gas producers that account for approximately two thirds of the total production in Texas.

The cost of drilling a well is affected by the choice and daily rate of the drilling rig, the availability of the derrick, the extra services required to drill the well, the duration of the well program (including downtime and weather time), and the remoteness of the location (logistic supply costs). For onshore oil and gas

exploration, the main determinant of the magnitude of drilling costs is the nature of the terrain and the target depth. The time to drill a well is difficult to predict due to geological uncertainties regarding the ability to drill the rock, formation fluid pressure, and depth. Between 70 and 75 percent of the drilling costs are proportional to the duration of the drilling: equipment hire costs paid to petroleum service companies and the costs of supervising the works (operating company personnel or prime contractor). The approximate average cost to hire a rig is $17,000 per day. The capital costs for the drilling contractor can be between $10 and $16 million for onshore equipment, which represents 20 percent of the total onshore exploration drilling costs. Onshore wells can be considerably cheaper to drill if the field is at a shallow depth, and historically, small businesses explore for crude oil at shallow depths around 4,000 feet.

Although it is difficult to estimate how the above costs will affect small businesses, the cost analysis defines the criteria used in determining the potential impact of new costs associated with the new rule. Based on averages from 2004 and 2007, the cost to drill an onshore oil well ranged from $1.7 to $3.9 million, respectively; the average time to drill an oil well is 30 to 100 days. To conservatively estimate the incurred costs, it was assumed that the cost to obtain a conventional drilling rig is $200,000, costing $1,000 per day to drill, and that it would take 14 days to finish the well; these numbers are considered unrealistically low. Assuming the lowest drilling cost of $214,000 and the highest cost estimates for a new registration provided by TXOGA of $5,000, the cost of the new rule is 2.3 percent of the overall drilling cost. Due to the lack of information available from either the

Texas Railroad Commission or the State Comptroller's Office regarding annual revenues from small producers, yearly earnings were not considered.

Cost Savings from PBR and Standard Permit.

One of the aspects of the proposal which generated many comments concerned LDAR and the recovery of fugitive vapors. The commenters fail to take into account that the adopted rules require only a physical inspection to catch and fix leaks along with minimal best management practices. If operators opt for the formal leak detection and repair program, this option results in the, and only if opted by operators, has expectations for a formal LDAR program. That result in the recovery of additional marketable product which will partially, and in some cases wholly, offset the cost of sampling, recordkeeping, and controls.

As the following cases will show, the control of emissions conserves and allows the recovery of product that would otherwise be lost, and ultimately, makes the OGS a more profitable operation. Recovery rates will vary based on the resources and diligence of the operator, but it seems clear that poor gas recovery not only forfeits profit but also wastes a finite resource. The EIA estimates that gas production will rise nearly 50 percent nationwide over the next 20 years. Texas will have a significant amount of that increase. At some sites within the state, actual emissions exceeded the emissions that were expected and reported from the site by over 300 tpy. The difference in the expected emissions and the actual emissions is attributable to poor gas recovery. With the expected increase in gas production,

recovery of product will generate increased profits, result in improved air quality, and provide additional domestic energy fuel supplies.

The Permian Basin Petroleum Association stated to the New York Times (NYT) in October 2009 that the use of infrared cameras is expanding as word spreads of the payoff in saved gas. A representative of Hy-Bon Engineering stated in the article that thousands of oil storage tanks regularly end up emitting large amounts of methane and other gases to the atmosphere. However, the companies that have taken the additional steps necessary to recapture their methane feel that this has ultimately been profitable for the company.

The NYT reports that BP began introducing methane-catching techniques at 2,300 well sites in New Mexico around 2000. The gas that would have otherwise escaped now flows through meters that field crews call the "cash register." The NYT further reports that from 2000 to 2004, emissions from BP wells in the region dropped 50 percent and by 2007, emissions had essentially ended. BP further stated to the NYT that on average, installing the vapor recovery systems cost about $11,000 per well. BP also stated that these systems have returned three times that investment in recovered methane.

These are not surprising statements. The commission has always been aware that good emission control at OGS can pay for itself and result in a greater net income for the industry.

EPA Gas Star Program.

EPA sponsors the Gas Star program, which is a voluntary participation partnership between EPA and the oil and gas industry. The purpose is to promote field tested methods of reducing emissions from oil and gas installations, reducing the emissions of air contaminants and increasing the recovery of marketable gas. The program maintains a website with emission control methods, their costs, and the expected payback period based on gas recovery.

A few examples illustrate the success of the program and resulting value to industry and the environment: In glycol dehydrators, the emissions of methane are proportional to the circulation rate of the triethylene glycol (TEG) gas used to remove water vapor from natural gas. Reducing the rate of circulation is a no-cost measure which can reduce methane emissions and lead to the recovery of marketable gas. The value to marketable gas recovered through this process alone ranges from $2,800 to $276,000, depending on the unit's throughput. Electronic flare igniters remove the need for a continuous pilot flame. These igniters can be installed for a cost of $1,000 to $10,000, and pay for themselves in 1 - 3 years. One partner reported that a no-cost action such as closing main and unit valves prior to maintenance blowdowns resulted in the saving of 9 million cubic feet of gas. At an average cost of $4 per thousand cubic feet (TXOGA, October 1, 2010), this is a savings of $36,000 per year in potential revenue.

Individual Oil and Gas Companies.

Independent of the EPA program, OGS owners and operators are discovering how

profitable product recovery can be. Anderson Oil Ltd. painted stock tanks in light colors and instructed gaugers and truck drivers to leave tank hatches open just long enough to gauge the tanks. They perform inspections and maintenance to ensure good seals and reduced VOC emissions by 1 tpy. This resulted in a savings of $1,000 per site.

Penn Virginia Oil and Gas, L.P. reported that the installation of an enhanced VRU at one of its sites resulted in an 8.38 tpy reduction of VOC emissions. Similar installations at other sites saved the company $98,952. XTO Energy installed a VRU on a large tank containing produced water and condensate, reducing VOC by 249 tpy. This reduction resulted in an estimated net savings of $45,625 at that site. XTO Energy installed additional field compression to reduce separator dump pressures. This reduced VOC emissions by 100 tpy and saved the company an estimated $10,000. XTO Energy also implemented a tank maintenance program, which includes seal and pressure relief inspection. This program reduced VOC emissions by 1,000 tpy and saved the company an estimated $500,000. Finally XTO Energy purchased two FLIR GasFindIR cameras for inspections and reduced VOC by 300 tpy, resulting in an estimated savings of $250,000 per year.

Gulfmark Energy in southeast Texas installed a VRU and repaired leaking seals at their Viola Station. Gulfmark also instituted required safety and environmental training for all field employees. These focused efforts reduced VOC emissions by 10 tons and saved $900,000 per year. EOG Resources purchased an infrared camera for leak detection. EOG estimates their self imposed leak detection

program saves the company $1,000,000 per year. They installed a VRU on a single condensate tank used for fuel gas and captured 200, 000 cubic feet of gas at a savings of $14,000 per year.

These are examples of a growing source of real world information maintained by the commission that demonstrates that good environmental control not only enhances air quality but can be a profitable business practice.

Houston Monitoring Project.

It is not the commission's intent to justify a rule based solely on the ability of an industry to pay for promulgated control measures. The commission is attempting to provide the proper context in which the phrase "affect in a material way" should be interpreted. The commission believes that the cost of controls compared to the resources of an industry is fair and reasonable. The implementation of these rules will cause the operating costs of the oil and gas industry to increase. However, that minimal increase will not affect the economic viability of the industry. The rules will help ensure that protection of natural resources is consistent with sustainable economic development, as well as protecting public health and the environment.

In 2007, the commission conducted a special monitoring project in its Houston region. The region monitored 30 sites, 17 of which (57 percent) had VOC emissions visible with an infrared (IR) camera. Leaking components included

hatch seals, pressure relief valves, water tanks, and glycol still vents. Downwind samples consistently documented concentrations of hazardous air pollutants such as benzene and toluene. Most emissions observed during the project resulted from a lack of routine maintenance on hatch seals and separator valves.

In 2010, the commission completed a similar survey of 22 tank batteries in the Midland region which revealed five tank batteries that were venting over 100 tpy. All of these venting tanks were found as a result of complaints.

A Fort Worth Star-Telegram editorial from November 8, 2010 cited a recent air quality study conducted by the Eastern Research Group (ERG) that the Fort Worth City Council hired to survey OGS in the city. ERG has surveyed 189 of about 400 sites in Fort Worth and found many more leaks than anticipated. Researchers using infrared cameras found detectable leaks in 68 percent of their tests, when they expected 10 to 25 percent.

The current oil and gas PBR includes no requirements for routine maintenance of equipment. As a result of the Houston surveys, the commission also realized the difficulty of determining compliance with §106.352. Due to the large number of methods used to estimate VOC emissions, determining compliance with §106.352 is extremely difficult. The new PBR and standard permit include best management practices which require closed hatches and seal of all units to be kept in good working order.

The growing use of the FLIR GasFindIR camera has allowed the commission's technical staff to characterize and assess emissions from OGS more accurately. Since 2006, the mobile response team (MRT) has conducted more than 25 monitoring trips to study these emission sources across the state of Texas including trips to Corpus Christi, Point Comfort, Ingleside, Houston, Pearland, Freeport, Texas City, Mont Belvieu, Beaumont, Port Arthur, Midland, Odessa, Longview, Mexia, Franklin, and Fort Worth. Further work by regional staff has established that natural gas and oil emissions are not confined to these areas, as they have been visualized, measured, and investigated in all geographic locations of Texas. The commission is still in the process of characterizing these emissions, but the use of the GasFindIR camera in other commission applications has led to the understanding that emissions have been historically underreported.

This underreporting was evident in the 2005 Upstream Oil and Gas Project when the commission provided technical guidance to a project that directly measured speciated VOC emissions from oil and condensate storage tanks at wellhead and gathering site tank batteries along the Texas Gulf Coast. New emission factors were established and the commission added approximately 700,000 tpy of statewide emissions. Additionally, the infrared camera detected many previously unidentified emissions along the Houston Ship Channel. Although the design of some of these storage tanks differ from the fixed-roof product and condensate tanks that exist at upstream oil and natural gas sources, all storage tanks are designed to equalize pressure to prevent both explosion and implosion incidents.

As a result, storage tanks of any type would be expected to release VOC emissions unless a vapor recovery system is installed to minimize emissions.

Follow-up investigations have indicated that many of these source types have underrepresented emissions. The new PBR and standard permit help resolve some of these underreporting issues by relying on site-specific or representative gas and liquid analyses, updated calculation methods, best management practices, and an evaluation of off-site impacts to show protection of public health and welfare for all new or modified sites.

One specific case of underrepresented oil and natural gas emissions was first identified through a commission's air-shed monitor that was located adjacent to a residential area. Commission investigators presented IR images to an energy company which showed excessive VOC emissions from storage tanks. The company hired an external contractor who measured and calculated these emissions for consistency with the company's claim of PBR status. After completing testing, these VOC emissions were actually estimated in excess of 370 tpy, more than 14 times the PBR VOC limit of 25 tpy. Though this is but one example of underreported emissions, commission investigative efforts tend to indicate that emissions of this magnitude are not confined to one company or geographic location but are occurring throughout Texas.

Commission monitoring and field assessments cover multiple natural gas and oil emission sources involved in the production and processing of oil and gas. These

sources include: drilling, fracturing, well-heads, condensate and product storage tank batteries, compressor stations, saltwater disposal wells, and natural gas processing facilities. These sources are permitted by the commission to release air emissions. However, several years of field work have demonstrated that a notable portion of fugitive emissions also come from other sources that are not regulated under the current PBR and standard permit. These sources include open tank hatches, tank seal issues, tank integrity problems, pressure relief valves, vent stacks, unlit flares, truck loading and unloading activities, vent gaskets, leaking vent flare arrestor caps, dirty flare arrestor caps, heater treater pressure relief valves, vessel fittings, controller boxes, vent control valves, gun barrel separators, glycol dehydrators, and blowdown valves.

Based on this information and information used to develop the rule proposal, the commission concludes that the current §106.352 is not adequate to ensure public health and welfare and does not meet the intent of the TCAA. The commission also concludes that the industry will continue to expand based on new techniques for extracting oil and gas and the rise of energy prices. The Texas Alliance of Energy Producers (TAEP) states that production in the Permian Basin has increased from 28.9 million barrels in January 2008 to 33.6 million barrels in January 2010, a rise of 16 percent. Much of this extraction will occur in areas that have seen little production in the past and are more densely populated than traditional producing areas. TAEP also reports that since June of 2009, oil patch employment in the Permian Basin has grown nearly 8 percent, the rig count is up more than 29 percent, and drilling permit applications are up more than 55 percent.

The commission believes this growth is good news for the Texas economy and is committed to helping ensure that the development of these resources continues consistent with good air quality. The anticipated increase in gas production makes it even more important that individual installations produce acceptable emissions to prevent the deterioration of ambient air quality and to keep the effect of emissions on individual receptors within ranges that protect public health. The commission has also determined that the control measures adopted in this rule are consistent with the wise development of a limited resource and will not have a materially adverse effect on the industry.

General Comments, Burdensome, Complexity

Numerous companies, organizations, and individuals submitted comments expressing concern that the rules will burden the oil and gas industry to the point that doing business in Texas would be undesirable or impossible.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA stated that any compressor or heated vessel operating at an OGS will have nitrogen oxides and other combustion-related emissions. Thus, based on the generally simple production operations at a typical OGS and as explained in more detail in these comments, a PBR or standard permit is the appropriate mechanism to authorize air emissions at an OGS. TXOGA contends, however, that these relatively simple operations do not merit the degree of regulation that would result from the proposed rules. In fact, as OGS are comprised of a series of fugitive emission sources and are subject to federal 40 CFR Part 60 NSPS and National Emission Standards for Hazardous Air Pollutants (NESHAPs) just as other similar fugitive emission sources are under the TCEQ rules, TXOGA questions the need to subject OGS to more stringent requirements at this time.

TAEP also believed that the proposed rule is onerous, excessively broad in scope and, as presented, it is a major change in the TCEQ approach to reporting and quantifying fugitive emissions from oil and gas facilities. Though all of the industry will labor under the rule as proposed, small producers and marginal production will be most burdened by the rule as proposed. The Alliance would suggest that both the resources of TCEQ and the Industry will be stressed and wasted under the unnecessary data gathering, sampling and permitting of the rule. They stated that, "It is imperative that we prioritize and focus on those facilities which have the largest potential to emit and the greatest threat to the health and safety of Texas citizens."

PBPA stated that increased costs to marginally economic oil and gas wells will have the effect of forcing operators to shut-in production. Since nearly 20 percent of United States domestic oil production is produced by such "stripper wells" the new rule will result in a direct and demonstrable loss of tax revenues, jobs, and domestic energy production.

Fountain Quail asked the TCEQ to not impose unnecessary regulations over our natural gas industry. The natural gas industry has been a boon for state's economy. False alarm news reports and unsubstantiated claims about potential environmental impacts of natural gas are being used to justify the need for imposing more regulations on the industry. Further regulations would inhibit these companies from investing in continued environmental programs. The state must continue to encourage investments in research and development.

Markwest Energy Partners commented that the rule would have significant financial and operational implications and would result in increases in cost and expenses for even the most minor modifications to facilities. Yet, the basis of the modifications is the Barnett Shale study which has little, if any, findings that warrant the significant and extensive proposed changes. This additional cost would have a detrimental impact on future projects in the State of Texas.

Devon is concerned that these rules "would impose a multitude of onerous and burdensome requirements on OGS that are neither practical nor economically feasible." They are concerned that the rules would "inflict significant cost increases on the oil and gas industry in Texas, delay or reduce production, and reduce taxes paid to the state, while providing minimal improvements with respect to protectiveness of public health and the environment. The rules would impose significant cost burdens on the oil and gas industry in Texas, including unwarranted recordkeeping, reporting, and monitoring, which ultimately result in insignificant air quality improvements. While Devon supports the TCEQ's efforts to assure that air emission standards for the oil and gas industry are protective of the environment and public health, they are highly concerned that these draft proposals inflict drastic increases in cost on our industry for minimal air quality benefit." It is their belief that "effective air quality regulations can be developed without substantial financial implications to oil and gas operators. Imposing additional cost on the operator ultimately affects capital investment including a reduction in wells drilled, fewer local jobs, a reduction in severance taxes and royalty payments, and creates a risk of financial "leakage" from companies allocating funds to more favorable regulatory environments."

Devon stated that based on its "understanding and interpretation of the proposed rules as written, its operating and capital cost impact is estimated at $21 million per year and up to $31 million per year, depending on the assumptions used in the estimation. This estimated cost impact is based on current and projected levels of activity in Texas. This conservative estimate does not include the cost impact of lost or deferred production due to permit approval delays and required pre-construction authorizations."

PBPA stated that the oil and gas industry is one of the precious few bright spots in the United States economy and it is no exaggeration to say that we cannot afford to impair the stability and growth of this major source of jobs and tax revenue. Further, there is no cap on what level of emissions controls TCEQ may deem adequate. Under the proposed, new rule, operators will have to procure or otherwise obtain a detailed environmental emissions inventory, conduct annual updates and keep records indefinitely. Potential costs of this would likely be between $1,000 and $2,500 annually for a small facility (small production battery w/one or two tanks) to $5,000 per year for larger, aggregated facilities (combined tank batteries serving multiple wells, etc.). Operators will need to quantify fugitive emissions at an estimated per-site cost of $1,000 to $2,000 for small facilities to upwards of $5,000 to $10,000 for larger, aggregated facilities. Operators will need to quantify emissions associated with MSS activities (flaring due to gas plant down time, emissions due to workovers, etc.). Estimated cost of this would be on the order of $1,000 for small facilities to $2,500 or more for larger facilities, assuming that TCEQ would accept mathematical estimation and modeling rather than substantially more expensive gas capture and chemical sampling and analysis. Total: $4,000 for small facilities to $17,500 per year for larger, aggregated facilities primarily dependent upon the level of detail that TCEQ will require.

PBPA provided a list of potential emission control costs. The estimated capital cost of installing a small, smokeless combustor for a small site may range from $10,000 to $20,000. Annual operating costs may be assumed to be $1,000 per year when maintenance and personnel costs are considered. The estimated capital cost of installing a VRU may range from $25,000 to $100,000 per facility. Annual operating costs may be estimated at $2,500 per year when maintenance and personnel costs are considered. Controls will need to be monitored for effectiveness on an annual basis, to include measurement of throughput and emission control effectiveness. Assume $2,500 as an annual operating cost per site for this. Tank painting costs could range upwards of $10,000 per tank or more.

PBPA stated that the TCEQ's new rule will require that all oil and gas operators to conduct a highly detailed environmental inventory on an annual basis for every oil and gas producing facility. We believe that the scope and recurring costs associated with this requirement is excessive and unnecessary for the purpose of accurately assessing production facility emissions levels. In this regard we refer to and applaud the excellent work that the emissions inventory section of TCEQ has done these past several years in developing and refining emissions estimation methodologies. We believe that it is an oversight on the part of the TCEQ rule makers not to include this work.

PBPA provided a list of potential administrative control costs. Add $1,000 to $2,000 per site per year for consultant and/or internal engineering personnel costs to oversee and administer the new monitoring and recordkeeping requirements, above and beyond the estimated costs indicated above. Thus, a 100-well operation will likely require $50,000 to $100,000 per year of environmental compliance service from a competent in-house employee or external consultant, as a risked cost for potential non-compliance despite good intentions and best efforts. Oversights and fines happen much more so with more stringent regulatory requirements.

Bart May Trucking commented that it depends on the oil and gas industry, particularly in the Barnett Shale Region. It opposes regulation that may cause companies to spend their money elsewhere. The oil and gas industry is an important part of the Texas economy. It supports clean air and water but believes the results of expanded air monitoring should be examined before regulation are adopted that make Texas a less attractive place to invest. Regulatory changes should be made on credible data only.

Christian & White Properties and Fort Worth Crushed Stone object to the unnecessary state-wide regulation of an industry that has allowed Texas to weather the recession better than many locations and provide jobs and a tax base for schools and local government services. The rules will put Texas producers at a competitive disadvantage. They believe the results of expanded air monitoring should be examined before regulations are adopted that make Texas a less attractive place to invest and that regulatory changes should be made on credible data only.

Bridgeport Chamber of Commerce stated that energy extraction and production have propelled the Texas economy and the development of the Barnett Shale region allows growth in the energy sector for decades. Any new regulations should be considered based on the relative risk posed by the industry regulated and the benefits of that industry. The state must be careful to strike a balance between overzealous regulation and safe operations. In North Texas, the gas industry has kept local economies afloat, and the state should not produce regulations that would cause these operations and the businesses supported by them to move to other states. This would remove the potential for Texas to be a leader in this form of energy production.

Parrish Field Services commented that the regulations will make the Barnett Shale less attractive for drillers and operators as opposed to other regions of the country. A migration of these operations would be catastrophic for this company and others like it supporting the oil and gas industry. The proposed regulations do not seem to be in response to any clearly identified environmental threat. The drillers and operators work hard to ensure the safety of their operations because they all live on the Barnett Shale and do not want to see the environment damaged, and want to grow the economy in a responsible manner.

Thirteen individual commenters expressed similar concerns about the importance of the oil and gas industry to Texas. An individual commented that the natural gas industry is critical to the economy of Texas and responsible for providing thousands of jobs and sustaining a strong and reliable tax base. The commenter understands the importance of balancing economic prosperity and energy independence with responsible environmental stewardship. However, a premature decision by the TCEQ could jeopardize that critical balance, resulting in over-regulation that will have a chilling effect on the production of clean and sustainable natural gas and the economy as a whole. Texas is blessed with an abundance of clean energy reserves and TCEQ must propose regulations based on scientific fact. Regulations based on faulty science and political pressure will only result in economic hardship and unnecessary penalties on companies who chose to invest in the state.

TXOGA understands that the federal 40 CFR Part 60 NSPS and 40 CFR Part 61 NESHAPs are currently under review by EPA and are likely to be revised soon to impose more stringent requirements on OGS. TCEQ should wait to see what changes will be made at the federal level so that potentially inconsistent requirements are not imposed at the state level that will place Texas operators at an economic disadvantage relative to similar operations in other states.

An individual has seen firsthand the positive impact of natural gas drilling in this state and is concerned that unnecessary regulation of oil and gas production will only enhance dependence on foreign and out of state sources of energy.

An individual commented that the proposed regulation threatens the livelihood of thousands of Texans who rely on the natural gas industry as an employer and driver of growth. The oil and gas industry provides opportunity and should not be restricted by further regulation without a cost benefit analysis. Unnecessary regulation could restrict the development of the Eagleford Shale region. The current proposal does not scratch the surface in delivering an environmental benefit for the expense. Considering the low cost-benefit and fragility of the economy, the proposed regulations should not be implemented.

An individual commented that the additional regulation will retard the development of energy resources and will threaten the state's economic viability as it struggles with high unemployment and a budget deficit. The oil and gas industry is already one of the most heavily regulated in the United States. While Texas regulators and lawmakers have been relatively accommodating in the past, the proposal and looming federal intervention exposes the industry to unnecessary regulation and uncertainty.

An individual commented that as a landman and a realtor he has seen the economic growth and improvements in schools, libraries, and firehouses that have been provided as a result of revenue from the oil and gas industry in the Barnett Shale region. These benefits should not be chipped away as a result of inconclusive monitoring. TCEQ should pursue comprehensive monitoring of the Barnett Shale to alleviate public concerns and before considering further regulations.

An individual commented that the benefits of the oil and gas industry to Texas are immeasurable. The proposal to place additional regulations on the industry is not a solution to a problem but a problem to a solution. The development of the natural gas resources can lead to national energy independence. Another individual commented that the natural gas industry is a critical component of the nation's domestic energy portfolio. It is in the best interest of the state to encourage development of this resource without driving away jobs or tax revenue.

An individual expressed opposition to the proposed changes in the PBR procedures for natural gas facilities. Excessive regulations will surely decrease the industry's competitiveness and negatively impact communities. By placing burdensome regulations on the natural gas industry TCEQ will drive jobs out of the state and stifle long-term development. Moreover, the costly regulations will diminish critical research and development funding which could lead to further advances in safety and environmental performance. The commenter believes TCEQ should continue to monitor water and air quality concerns throughout the region to ensure the safety of residents. However, TCEQ should stop short of changing the existing regulatory framework until accurate and comprehensive data has been analyzed. Natural gas resources can and should continue to sustain the Texas economy in the coming decades. The commenter questioned why the state would not want to use what it has already and why we continue to fund the radicals in the Middle East by purchasing their oil. Drilling for oil and gas does cause some harm to the environment, but we can't be perfect at everything. He asks if you would rather fund Al Qaeda or have a booming domestic economy for years to come. Environmentalists are ruining the competitive advantage that the United States once had. He is for cleaning up the industry practices, but to enforce pointless regulation is flat out stupid. He states we must recognize the critical role these companies play in both the public and private sectors and ensure they will continue to invest in our communities.

Senator Robert Nichols, Senator Kel Seliger, Representative Warren Chisum, Representative Wayne Christian, Representative Tom Craddick, Representative Kelly Hancock, Representative Rick Hardcastle, Representative Ken Legler, and Representative Randy Weber issued the following comments: "We have been closely monitoring the TCEQ's proposed rule changes to PBRs and standard permits for OGS in Texas, and feel compelled to write you to express our concerns. The TCEQ mission statement puts forth that "the Texas Commission on Environmental Quality strives to protect our state's public and natural resources consistent with sustainable economic development." This mission is two-fold; however the permitting changes that the agency is proposing seem only to contemplate the former of these charges. Oil and gas in Texas employs over 315,000 people, pays $13 billion in property taxes, $4.1 billion in severance taxes, $926 million in sales taxes, and $1.1 billion to the Permanent School Fund and Permanent University Fund every year. And yet, in the face of a budget deficit that, by the latest estimates, could top $18 billion, rules are being pushed forward that could have a devastating effect on an industry that is one of the largest economic drivers in the state. The official "agency philosophy" that accompanies your mission statement dictates that agency decisions be based upon "the law, common sense, good science, and fiscal responsibility" and that the agency will "ensure that regulations are necessary, effective, and current." Considering these objectives, how can TCEQ propose massive changes to air permitting for oil and gas when the jury is still out regarding the impact of oil and gas on air quality? Numerous studies and initiatives on these impacts are in progress. If common sense is indeed employed, it dictates that the promulgation of rules without knowing whether, or to what degree, additional regulation is necessary is an irresponsible exercise and a waste of taxpayer dollars. This lack of fiscal responsibility will be even further highlighted should results of ongoing studies show a negligible environmental impact resulting from oil and gas. With so much on the line at such a critical time, we ask that you please be sure you are taking adequate time to ensure that these rules are promulgated correctly, and with accurate information. If that information is not yet available, please do not allow public opinion, media attention, or threats from the federal level to prematurely drive regulatory decisions. The oil and gas industry provides so much for Texans; the least we can do is be sure we are doing the right thing before moving forward."

TIPRO stated that the jury is still out on the exact level of impact that oil and gas operations have on air quality, and numerous studies and initiatives (including TCEQ own studies) have yet to be completed. Legislators have called for additional monitoring in high-risk areas, indicating their desire to further study the issue and gather accurate data. To pass regulation which will have a profoundly negative effect on a vital Texas industry is premature and unnecessary at this time. Should these proposed rules be adopted and studies of oil and gas operations subsequently show the impact on air quality to be negligible, it will result in the additional expenditure of time, taxpayer dollars, and resources to properly remedy the rule changes the TCEQ seems so determined to push through on a strict deadline. The agency's goal should be to get the rules done right, not fast. There are well over 5,000 active producers in Texas. Of those, the vast majority are smaller independents. Together, the small independent producers account for a majority of the oil and gas production in the state, with a large portion of that production coming from marginal wells. If drawn into the new PBR and standard permit system, these small operators will have such a disproportionate financial and administrative burden placed on them that the likelihood of their operations remaining viable is drastically diminished. This could potentially result in enormous losses in terms of reserves, tax payments to the state, and employment in the field. Further, we are likely to see a sharp increase in the number of wells plugged and abandoned.

The commission is aware that regulatory actions affecting the oil and gas industry affect the entire state economy. A significant portion of the Texas workforce is employed directly by the industry and the small businesses that help support it, and the commission is in complete agreement that a robust oil and gas industry is good for Texas and the nation. Other factors also make a community or state a desirable place to live. The ability to enjoy one's property or public space not only adds to that desirability, but is a powerful economic draw that is proven to attract a variety of businesses and industries. These rules help ensure that clean air remains an attribute of the majority of Texas communities, and that the steady improvement in air quality in the state's larger cities continues.

It is clear from the information presented in the commission's previous response that the oil and gas industry is in the process of a rapid and sustained expansion. The commission is pleased about the economic benefits that will follow. The adopted rules are based on a thorough investigation of the industry, and the

obligation to balance environmental benefit and economic growth was uppermost in the commission's considerations.

The commission does not deny that a significant number of facilities will incur costs as a result of these rules. The commission has previously stated where it respectfully disagrees with itemized cost estimates from the industry, but the commission agrees with the scale of capital costs estimates for individual control equipment as submitted by PBPA. The commission made similar estimates in the fiscal note of this rule proposal. The cost of the most expensive of controls, and these would only be installed at new high producing sites near receptors, are a small fraction of the cost of bringing a well into production. Additionally, controls such as VRUs recover saleable product to partially or wholly offset their cost.

The commission has considered the air quality benefits and the potential costs of these rules and has determined the rules are necessary to prevent the deterioration of air quality. Some control measures will be expensive, but the scale and resources of the industry are proper considerations in a determination of whether the rules are a reasonable exercise of the commission's authority. The commission believes that the economic effect of this adoption does not rise to the level of forcing an industry out of a state where so much of an increasingly valuable natural resource is located.

The oil and gas industry appears to be in the midst of a new boom. New technologies have made hydraulic fracturing an economical possibility and have

allowed industry to tap into shale gas that was previously far too expensive to extract. This new boom is the result of technologies and methods that have evolved over the years. And while the technology for drilling wells and producing oil and gas has evolved, the laws governing this industry have not. Texas still operates under the same PBR that it adopted in 1997. The rule adopted in 1997 is a relic from the Standard Exemption List. The Standard Exemption No. 66, which governed Oil and Gas Facilities, became effective in 1986. Essentially, Texas is applying 25 year old rules to an industry where science and technology are evolving on a daily basis.

Not only has science and technology allowed us to tap into previously unattainable resources, it has also allowed us to better understand the effect of oil and gas drilling operations has on public health and the environment. Again, the most up-to-date science and emission detection systems have greatly evolved over the past 25 years. Unfortunately, our laws have not. While the Standard Exemption reflected current science in 1985, it does not reflect current science in 2010. The science of 2010 dictates that the PBR and standard permit be updated in order to allow increased air emissions and protect public health and the environment.

Cost of New Rule, Basis for hourly wage.

The hourly wage for an employee was based on TXOGA's estimate that annual compensation including taxes and benefits for one employee is $90,000. It was assumed that 20 percent of that amount is overhead. Therefore, the annual salary is $70,000 per employee. Based on a 40-hour work week and 52 weeks a year, the

hourly wage is $33.65 per hour. To conservatively estimate costs, this rate was rounded to $35 per hour.

Much of the information required about a site is commonly available information or information that is require for other purposes. For example, the Texas Railroad Commission requires certain information about a site and gas analyses that in some cases can be used to complete registration forms for the commission. Companies can minimize costs by gathering the information needed at the same time and submit it to both agencies as required.

Geographic coordinates.

The Core Data requested during the notification and registration process includes the geographic coordinates of the OGS. Once the coordinates are entered, the ePermits database will maintain the information so that it will not need to be reentered, saving time on subsequent submittals. Although there is a perceived cost to obtaining a site's geographic coordinates, the information is easily obtainable. It is not necessary to physically send a person to every OGS to obtain the geographic coordinates. Existing sites that are required to provide historical notifications will also have previously provided a site plat to the Texas Railroad Commission. A plat is required by Statewide Rule (SWR) 5 in order to complete the Form W-1 Application for Permit to Drill, Recomplete, or Re-Enter, which is a required form for all oil or natural gas wells. The plat information is used to generate geographic coordinates that are plotted and made publicly available for free in the Texas Railroad Commission's Public GIS Map Viewer for Oil and Gas

Wells, Pipeline Data, and LP Gas Sites (*http://www.rrc.state.tx.us/data/online/index.php*). It is possible to use a variety of search criteria, including commonly available site identification information such as the API well number to obtain the geographic coordinates. In addition, since companies are required to conduct surveys to obtain accurate data from which to draw the plat, companies can reduce cost by having the surveyor take the geographic coordinates when at the site. The commission notes that in the last few years there has been a surge in the development of handheld devices, including many cell phones, which can provide geographic coordinates. Furthermore, the commission provides the TCEQ USGS Topographic Map Viewer (*http://www.tceq.state.tx.us/gis/drgview.html*) to obtain the geographic coordinates. Other free websites include Google Earth (*http://www.google.com/earth/index.html*) and Microsoft Research Maps (*http://msrmaps.com/advfind.aspx*) that can provide geographic coordinates by entering a physical street address or locating a site on the map.

Gas Analysis.

The cost of an analysis on the various product streams at an OGS will vary. The most typical type of sample is the pressurized inlet gas sample. Once this gas is depressurized in the lab, the resulting gas and liquid phases can be analyzed and the results used in several emission calculations. Some of the other tests done by a lab include other pressurized samples at other points during the process and a separate H_2S analysis by GC. An H_2S analysis done at the site by a stain tube method could be done by personnel already at or visiting the site for other

reasons. This test would cost approximately $60, and take 30 minutes, though there would be an initial training of personnel for running the test. This training would take about four to eight hours, based on techniques and troubleshooting. The cost is based on the fact that the stain tube measures H_2S in ranges and it could take up to three tubes to get the right range. Each tube is about $20 based on searching the web for cost of tubes. Tests run by a lab start at $400 and go up to $1,200. This range is based on the type of test and who does the sampling. The sampling can be done by the company, but if there is any error in the sampling, then the company would have to resample and resubmit the sample to the testing lab and pay the fee again. If the testing lab goes out to sample, they will charge a fee for the sampling based on the site's location and how quickly the company wants the results. However, if the lab does the sampling, and the sampling is done incorrectly, the lab will go back out and resample at no extra cost to the company. Testing labs do provide a discount if a company has many sites in a similar area that can be collected analyzed in one trip. In addition, testing labs do provide a discount if companies agree to a contract for testing of all of a company's OGS. The amount of the discount will vary depending on how many sites a company owns. The Texas Railroad Commission requires initial sampling and quarterly sampling of certain OGS based on production rates through hexanes or compounds with seven chained carbon atoms (C7). Although the commission requires samples through a minimum of ten carbon atoms (C10), which includes BTEX, companies can reduce the number of required samples and greatly minimize costs by requesting C10 samples. The company can then submit the same lab test results to the Texas Railroad Commission and to the commission as

part of the registration documentation.

Records.

There are many required records to be kept to demonstrate compliance with the PBR and standard permit. The recordkeeping is required by §106.8, but to insure practical enforceability the commission has stated what records need to be kept for demonstrating compliance under this section. However, in any instance in which records are being kept for other purposes, but show the same information, this will be acceptable to the commission. This will require no additional paperwork, man-hours, or time to demonstrate compliance.

Notification and Registration, Historical Notification.

Existing OGS are required to provide notification through ePermits using the APD OGS Historical Notification. The notification will provide basic identification for the site, including an updated Core Data, the previously claimed historical versions of PBR §106.352, lease name, and well numbers as provided to the Texas Railroad Commission. All the information that is requested is information that the owner or operator of the site will have provided to the Texas Railroad Commission or will have maintained in historical records for each site. Based on the Office of Water's estimate of their current applications in ePermits, it will take an applicant about 30 minutes to fill out the notification information from start to finish, at an hourly wage cost of $17.50. No fee is charged for historical notifications for existing sites.

New project notification.

Notification information for proposed sites to be constructed will include the same information as requested in the historical notification through ePermits using the APD OGS PBR Level 1 or Level 2 Registration Historical Notification. Companies will indicate the section of the rule under which they expect the site to fall, PBR Level 1 or Level 2, or the standard permit. Since the information for new project notifications includes only basic identification information, the same as required by the Texas Railroad Commission, and companies are not required to provide complete process information and emission calculations with the notification, it will take an applicant about 30 minutes to fill out the notification from start to finish, an hourly wage cost of $17.50. The Agency fee for new project notifications will be $25 for small businesses and $50 for all others.

Level 1 PBR Registration (new and revision).

Level 1 registration includes the same Core Data information as the notification process. Companies can complete the registration process by using ePermits. Since companies will have already entered this information during the notification step, the administrative information will be automatically completed and the person completing the information will need to verify it is still correct. Registrations will also require background information, emission calculations, and documentation to support the represented emission rates. It is estimated that it will take one hour to complete the ePermit application since it is considerably longer than the notification process, an hourly wage cost of $35. The fee for a Level 1 registration is $25 for small businesses and $175 for all others. The

combined fees for a new Level 1 OGS is half of the regular fees ($50 small businesses, $225 all others) and is divided between the New Project Notification and the Level 1 PBR Registration. The fees for PBRs currently are $100 for small businesses and $450 for all others.

Level 2 PBR Registration (new and revision).

Level 2 registration includes the same Core Data information as the notification process. The commission's intent is that companies can complete the registration process by using ePermits. Since companies will have already entered this information during the notification step, the administrative information will be automatically completed and the person completing the information will need to verify it is still correct. Registrations will also require background information, emission calculations, and documentation to support the represented emission rates. It is estimated that it will take one hour to complete the ePermits application since it is considerably longer than the notification process. The fee for a Level 2 registration is $75 for small businesses and $400 for all others. The combined Level 2 fees ($100 for small businesses, $450 for all others) are also divided between the New Project Notification and Level 2 PBR Registration. There are no extra fees for any of these new applications over the current PBR registration fee.

Potential Costs associated with Planned MSS

The new rule requires that certain types of planned MSS activities, which have the potential to result in a substantial amount of emissions, be quantified by January

5, 2012. This requirement is further codified in §101.222(h)(1)(E). The emissions from these events and activities can be calculated using the Agency-created Oil and Gas Emissions Calculations Spreadsheet that is available at no cost on the web (draft available for comment at *http://www.tceq.state.tx.us/permitting/air/announcements/nsr-announce-10-29-10.html*).

The costs associated with claiming any planned MSS before the required date should be considered as the hourly wage for whomever is compiling the data, entering the data into the Agency-provided spreadsheet, and either submitting it through ePermits or as a paper application. While planned MSS emissions were not previously required to be represented, quantified, or considered in site-wide emission estimations for oil and gas PBRs, the requirements of Chapter 101 will go into effect on January 5, 2012, at which point, all OGS will be required to report MSS activities. It should be noted that Chapter 101, Subchapter F, amended to be effective January 5, 2006, allows up to 6 years after the effective date of this section before oil and gas companies are required to authorize planned MSS emissions.

Although the new rule requires that certain records are kept, this is not a new requirement per §106.8, which has been in effect since April 2002. However, for the types of planned MSS activities that will not result in a substantial amount of emissions, only records must be kept; emission calculations are not required to be submitted. The types of records that should be kept include the types of activities,

such as cleaning, replacing, or testing activities, as well as the duration of activities and/or the cause. The way in which records will be created and maintained is at the owner's or operator's discretion. The cost of creating and maintaining these records should be minimal as the MSS activity will have already been recorded as part of the process. Additionally, the cost of keeping these records would go into the cost of paying personnel responsible for environmental compliance.

The rule is also allowing emissions from engine-driven compressor startups that are associated with preventative system shutdown activities which will be authorized, as opposed to being considered an emissions event or upset, provided that certain conditions can be met. The conditions are: A) prior to operation, alternative operating scenarios to divert gas or liquid streams are registered and certified with all supporting documentation; B) engine-driven compressor shutdowns shall not result in emissions; and C) emissions which result from subsequent compressor startup activities are controlled at a minimum of 98 percent efficiency for VOCs and H_2S. The registration and/or certification fee varies based on if the company is claiming Level 1 or Level 2. The notification fee is $25 for small business and $50 for all others, Level 1registration fees are $25 for small business and $50 for all others, and the Level 2 registration fees are $75 for small businesses and $175 for all others. There would be a cost associated with controlling the emissions if a control device capable of at least 98 percent efficiency for VOCs and H_2S is not already in place, but the control requirement is voluntary because registering this emission type is an option. Only if this emission type is chosen to be authorized, is the control required. Having the emissions

authorized would prevent the issuance of fees that could result from fines associated with unauthorized emission events or upsets.

Potential Costs associated with Leak Detection and Repair (LDAR)

Companies are not required to implement a LDAR program unless a company is claiming a reduction in its fugitive emissions in order to meet a required emission limit. However, as noted earlier, the EPA Natural Gas STAR program has found the monitoring fugitive emissions can be one of the easiest and cost-effective ways to reduce emissions and increase production. If a company is required to implement a LDAR program, then it should be maintaining a record of quarterly and weekly walk-through associated with an LDAR program. Inspections include details of a fugitive component monitoring plan, and LDAR results, including quality assurance and quality control. Fugitive components need to be routinely checked to detect possible leaks or ruptured disks on pressure sensing devices. Estimated costs are $1.25 per component for full LDAR inspection. The time estimated to complete the inspection for OGS will vary on complexity and size, but an inspection of a typical site is 30 minutes per quarter and 30 minutes per week. These costs will not be new for existing sites where companies have already chosen to implement a LDAR program. Further, the new PBR will not require a full LDAR program therefore the $1.25 per component is a very conservative cost estimate for inspecting components should a company choose to use this method to meet requirements in the rule.

Potential Costs associated with Flares

Companies that operate sites with flares should currently be following regular monitoring according to NSPS 40 CFR §60.18. In addition, §111.111(4) regarding visible emissions applies to any flare. The cost of this monitoring is about $4,000. Voluntary 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. Companies cited this cost to range from $1,000 to $24,500. However, the monitoring requirements in this rule are the same as the previous requirements. Therefore, there is no new cost imposed on companies.

Potential Costs associated with Engines, Turbines, and Other Non-control Combustion Devices

The commission is no longer requiring quarterly engine testing for OGS under the new PBR. The new requirement of semiannual engine testing applies only to OGS that are subject to Title V Federal Operating Permit requirements. The semiannual testing of engines is expected to cost approximately $45 for stain tubes ($7.50 per stain tube; three stain tubes for NO_X testing and three stain tubes for CO testing) for each test that is conducted, and will require 20 minutes of labor from the person conducting the test. Labor costs will vary from company to company, and we have assumed, based on TXOGA's numbers, that the hourly wage is $35 per hour. The use of stain tubes requires minimal training; training, which would take

no longer than 10 minutes per employee, would be considered as part of the personnel's hourly wage and would be an internal cost, not a cost associated with a consultant. The additional recordkeeping requirements would be minimal as well. Outside of the new semiannual testing required for OGS subject to Title V, no other requirements for engines have changed in the new rule except those that reflect federal requirements.

Engine requirements were re-evaluated in subsection (m), Table 7, Engines & Turbines, Initial Sampling. The commission does not consider that there will be an increased cost to the company as a result of changing engine requirements that will reflect federal requirements. Overall, engine costs are expected to decrease as a result of less stringent requirements, as well as a cost savings of about $5,000 per each claim of previous initial testing for some engines. Subsection (m), Table 9, Engine and Turbine Emissions and Operational Standards, contains phase-in periods for engines meeting NO_X emissions standards. More efficient catalyst controls are expected to be needed for some engines to meet the Table 9 NO_X standards in the new rule. Normal replacement of spent catalysts, which have no more than a 10-year expected life, is expected to occur during the phase-in periods. The incremental cost of increasing catalyst efficiency during normal replacement is expected to be less than $6 per hp, and the replacement catalyst is expected to have a 10-year expected life, after which the next normal catalyst replacement will have an incremental cost increase of zero dollars. There is an increase cost associated with the NO_X and CO testing of turbines under Table 7 which was not previously required in §106.512. The cost of the NO_X and CO testing from turbines

is expected to be $5,000 per test for initial testing and for biennial testing. The oil and gas industry was not directly concerned with the cost of testing for turbines based on the comments the commission received. Based on the commission's experience, turbines are expensive and less-forgiving of substandard operation in comparison to engines. It is in a company's best interest to test turbines to ensure proper operation of the turbine. Additionally, testing may be required for turbines subject to any applicable federal rules.

Testing is not required under the new rule for other non-control combustion devices. There are no other cost increases associated with engines, turbines, or other non-combustion control devices under the new rule, as any other requirements in the rule not discussed above were either already required (such as recordkeeping under §106.8) or did not have changes in comparison to what is already required.

Potential Costs associated with Storage Tanks

Based on a survey of tank manufacturing facilities, the cost to replace an existing tank, whose integrity has been compromised or that has structural damage, and install a new 400 barrel storage tank is approximately $22,000 per tank. For companies who choose to have tanks painted a particular color, either to reduce emissions or reduce solar absorption, the cost to have a tank painted in a fabrication shop is less than $2,000. The cost to have a tank painted on-site would cost more; however, it is the commission's expectation that companies would take the opportunity to paint a tank while it is already down for other maintenance

needs to minimize the cost and the amount of time the tank is out of service. The recordkeeping requirement (one hour per quarter) would be included as an hourly wage for the person inspecting the tanks. Again, using TXOGA's figures, the person conducting the physical quarterly inspection of the tanks would be paid $35 per hour, four times per year.

There is no direct cost to a company associated with having storage tanks on-site, as every site will be required to notify the Agency via ePermits. For larger, more complex sites who will have to quantify and report their emissions, there may be additional registration fees under §106.352; any maintenance of tanks, including surface coating, would be included under §106.263.

In order to quantify emissions from storage tanks and other equipment (including but not limited to glycol dehydration units and amine sweetening units), companies have a multitude of options available, some of which are free of charge. For example, the Tanks 4.09d program (*http://www.epa.gov/ttnchie1/software/tanks/*) and the WATER9, Version 2.0 program (*http://www.epa.gov/ttnchie1/software/water/index.html*) are both free and provided by the EPA. The Vasquez-Beggs Correlation equation, used to estimate flash emissions, is available and there is no associated cost. However, there are different costs associated with more sophisticated software: GRI-GlyCalc 4.0 $140; E&P Tanks $450; AmineCalc $500; Flow Phase Aqualibrium $1,000; ProMax and/or Hysis $10,000-$16,000. Although the commission does not require a particular method to estimate emissions, the commission does

encourage companies to use a method that is conservative for operations at their sites.

Potential Costs associated with Vapor Recovery Systems (VRS)

The cost to install a VRS will be highly dependent on the pressure in the natural gas pipeline and well as the volume of gas in the pipeline. A typical VRS can cost between $30,000 and $100,000. However, based on numerous findings by companies and reported through the EPA's Natural Gas STAR program, a VRU can significantly reduce emissions, as well as increase the amount of marketable product, and therefore, increasing profits from natural gas operations. Only companies claiming over 95 percent control efficiency for a VRS will be required to monitor emissions, which are about $1.25 per component.

Potential Costs associated with Glycol Dehydration Units

The cost to install a glycol dehydration unit will be highly dependent on the pressure in the natural gas pipeline, the volume and quality of gas in the pipeline, as well as the type and amount of glycol used in the unit. A typical glycol dehydrator can cost approximately $100,000-$250,000. The cost of different glycol solutions is greatly dependent on supply and demand. The more popular types of glycol used in glycol dehydration units, such as monoethylene glycol (MEG), diethylene glycol (DEG), and TEG will be typically less than much rarer forms of glycol such as tetraethylene glycol (TTEG). Typically, TEG is the most expensive form of glycol of the three most common glycols used. While pricing for glycol is typically a trade secret to maintain competitiveness, the going rate for

TEG is about $30 per gallon. With the large amount of TEG being used in the oil and gas industry, one would assume that companies receive a 30 to 40 percent discount, reducing the cost to $18 - $21 a gallon. MEG and DEG, being of less quality, are cheaper, respectively. Determining the type of glycol to use at an OGS is dependent upon each site's individual condition(s) and the type of treatment the natural gas may need for normal operations. Companies should continue to maintain records that support the actual efficiency and emissions from the glycol dehydrator unit. Additional sampling of glycol dehydrator combustion exhaust is only required if the company elects to claim enhanced efficiency of a combustion control device, which would cost approximately $5,500 per sample.

Potential Costs associated with Cooling Towers

Companies are only required to keep records of the maximum cooling water circulation rate and basis, the maximum total dissolved solids allowed as maintained through blowdown, and the tower design drift rate if the cooling system is used to cool process VOC streams or if control from drift eliminators or minimizing solids content is needed to meet particulate matter emission limits. The time to do record keeping of the cooling water circulation rate and basis, and maximum total dissolved solids is estimated to take 30 minutes for a potential labor cost of $17.50. Cooling tower enhanced leak monitoring is voluntary unless monitoring indicates that the cooling water concentration is over 0.08 ppmv VOC or if control from drift eliminators or minimizing solids content is needed to meet particulate matter emission limits. The sampling cost is approximately $600 and one hour to conduct (at $35 per hour). Records must be maintained of all

monitoring data and equipment repairs.

Potential Costs associated with Tank Truck Loading

There are records that should be maintained regarding liquid loading into tank trucks; however, based on the requirements of §106.8, most of the requirements are not new and as a result, there is no new associated cost. Furthermore, the Texas Railroad Commission has long required companies to submit a Form PR Monthly Production report that tracks production, storage of liquids on-site, and how product was transported off-site. Additionally, transporters are required to submit a Form T-1 Monthly Transportation and Storage Report that details the product and quantity transported off-site. Some loading operations will use vacuum trucks or portable pumps to push material into truck and records of the type of control should be maintained. Storage tank loading should include flash for short-term emissions; however, short-term storage tank emissions including flash should be currently estimated. This is not a new requirement or cost to the company, but sample costs are estimated at $600 per tank plus an additional hour of labor (at $35 per hour). Records should also include the type of material being loaded into the truck, the amount being transferred, the duration and method of transfer, as well as the condition of the tank truck before loading commences. These records will take approximately 5 minutes to record per tank truck. Records of tank truck certifications and tests is required if a connection to control emissions is used and credit is claimed for the use of certified, leak tested trucks. If records are not kept, the company should have on file a copy of the Department of Transportation certificate from the trucking company verifying that the trucks

are 40 CFR Part 60 NSPS and/or 40 CFR Part 63 MACT leak tested. The time allotted to maintain these records is approximately 20 minutes per truck every 6 to 12 months.

Summary of Adopted PBR Costs

The cost will vary based on whether the company is notifying or registering under Level 1 or Level 2, which is based on total site-wide emissions. Fees are based on company size using the following criteria: less than 100 employees, less than 6 million dollars in annual gross receipts, or a governmental entity with a population less than 10,000. Actual registration costs will decrease for sites that qualify under Level 1 of the new PBR and register using ePermits. There will be minimal cost incurred as a result of the new rule outside of the additional need for recordkeeping. This cost will vary based on the number hours needed to obtain and/or maintain data, the hourly wage per employee for different companies and the number of employees needed to complete any given task.

Companies will be required to document the maintenance plan for each OGS. This process will require pulling together existing documentation and making copies of records to include in the maintenance plan. The cost to create the maintenance plan is estimated to be about 10 percent of a full-time employee salary. There is no new cost to meet the new PBR requirements for engines or turbines. The worst-case scenario would be upgrading an old catalyst on a rich-burn engine to meet the new standards, which will cost approximately $300 assuming that all sites have to do this. Companies are not required to upgrade catalysts until 2020, or replace

engines or turbines to meet the standards until 2030. Since companies will amortize capital costs over a 10-year period, and the closest standard date is in 10 years, there will be no new actual costs to meet the standards in the new rule. At the time the catalyst, engine, or turbine is replaced, it will be at the end of its normal operating life and will have depreciated such that there will be no choice than to replace it.

For the small fraction of sites with open-top tanks that have been modified and must meet the new rule and that have the potential to emit at least 1 tpy of VOC and 0.1 tpy of H_2S from produced water, companies will be required to enclose the tanks. The cost of a new 400 barrel tank is approximately $20,000. However, for the purpose for these evaluations, it is not included in the overall cost to permit a new site since it is an extremely rare circumstance. Therefore, the potential cost to enclose the produced water tank will apply only to a small segment of the industry. Furthermore, this cost will only apply to new sites or if a company makes physical changes at a site.

Companies will be required to perform quarterly inspections of sites. A worst-case cost for inspection of fugitive components, logging them, and creating records will be approximately $140 per year based on four one-hour inspections per year.

Companies are not required to include planned MSS emissions until January 5, 2012. Companies with existing sites will be required to evaluate MSS emissions for protectiveness. However, they are not required to report them and revise the

site's registration until 2012. The potential costs associated with evaluating these emissions will be two man hours at $35 per hour using the commission-provided spreadsheet and tables.

BMPs, including the use of control devices and LDAR programs to reduce emissions, are considered optional unless a company chooses to employ these methods to meet an established emission limit in the new rule. Therefore, there are no new costs imposed for sites that can otherwise meet the rule requirements. For sites that choose to control emissions, the cost of meeting the new rule will vary depending on the method selected the size of the site, and additional recordkeeping.

Based on the quotes received from the Air EnviroMentors discussed above, the only new cost incurred will be from sampling, which is expected to be $1,200 to $2,000. To reiterate, companies who choose to use a representative sample for many sites will have further reduced costs per site. Therefore, the most a new site will cost any given company will be about $3,000. This amount is exactly 40 percent less than the estimated cost that TXOGA quoted of $5,000 per site.

TPA recommended that instead of proceeding administratively with this effort, the TCEQ act together with industry and other interest parties in fashioning legislation that would authorize a new type of site-wide authorization that is workable for the oil and gas industry and that meets the goals of the TCEQ. Alternatively, TPA would urge the TCEQ to abandon this approach and propose a new structure implemented with such defined terms as "project," "scope of registration," "scope of protectiveness," and "scope of impacts review," as discussed."

The commission has revised the definition and scope of "project", "registration", and "impacts" evaluation requirements and exemptions in response to this and similar comments. The commission respectfully disagrees with industry that legislative action is required to update the PBR and standard permit. However, the commission is firmly committed to working with industry to continue to develop easy-to-understand and practically enforceable tools and mechanisms to ensure minimization and accurate quantification of emission releases.

TAEP stated that they are "not adverse to TCEQ knowing location of facilities but not interested in collecting data, analyzing samples, and compiling paperwork which is not a good use of resources for the agency or industry."

The commission will only be requiring historical sites to submit minimal data for identification purposes. The information required will not be in excess of information that should currently be on file for each site. It is not the commission's intent to require companies to waste resources which is why the notification only requires sites to submit the rule claimed as authorization, lease name, well number, latitude and longitude location for each site.

Fasken commented that they had "seen the cost estimates provided by the Permian Basin Petroleum Association to install smokeless combustors on flares, purchase and operate VRUs, and paint tank batteries in reflective colors. Fasken believes the potential costs associated with these proposals would be an economic hardship for many independent operators. Fasken disagrees with TCEQ's analysis that there would be no significant economic effect and states that TCEQ needs to perform an economic analysis as required by THSC, §2001.0225. Fasken is concerned about the immediacy of the implementation of these regulations and that all operators will be scrambling to purchase equipment and get facilities into compliance, adding to the economic hardship. Fasken believes that the heart of the proposal is dramatically lowered standards for VOCs, H_2S, and SO_2. No other gas producing state has limits this low. Fasken proposes that the regulation be withdrawn and a new coordinated effort between TCEQ and the industry begun. "Input from the oil and gas community is critical to balanced regulation."

The PBR does not mandate control unless it is necessary to meet emission limitations of the rule. Additionally, the phased implementation of this rule should provide ample time for the industry to acquire any needed control equipment. If an applicant can establish that their facilities and operation at their location are unique and should not need to meet the emission limitations of this rule they may apply for a case by case NSR permit.

TXOGA commented that, "Examples of how the proposed PBR and the proposed standard permit are overly prescriptive and onerous compared to other PBRs and standard permits adopted by the TCEQ are numerous, but are highlighted by proposed §106.352(b)(6)(B) and subsection (b)(6)(B) of the proposed standard permit, which would require OGS to conduct a case-by-case health impacts evaluation. The case-by-case evaluation and demonstration of compliance with ambient air standards and effects screening levels ("ESLs") that would be required by those proposed subsections would be legally inappropriate to include as a condition of the proposed PBR or proposed standard permit since to do so would not be in "in harmony with the general objectives of the Act involved. TCEQ's air monitoring and toxicological studies have demonstrated that the current PBR establishes requirements that, if followed, result in insignificant contributions of air contaminants to the atmosphere. The proposed additional case-by-case evaluation provides no additional environmental benefits, but greatly increases the complexity of the OGS PBR and standard permit, and is, therefore, arbitrary and unreasonable. Furthermore, the TCAA clearly indicates that the Legislature intended for TCEQ to establish different levels of review and complexity for PBRs, standard permits, and individual permits. To require a facility to undergo a case-by-case evaluation of health effects in order to qualify for a PBR and/or a standard permit would make the review processes for the different authorizations strikingly similar in many important respects (i.e., the process for PBRs, standard permits, and individual permits would be equalized with regard to the case-by-case review). Thus, adopting the proposed rules would in important respects "equalize" the different permitting mechanisms. Equalizing the permitting mechanisms would not be in harmony with the legislative intent that can be gleaned from the plain language of the statute - which is to distinguish PBRs, standard permits, and individual permits from each other. Thus, TXOGA urges the commission to remove the requirement in the proposed PBR requiring a case-by-case health impacts evaluation in proposed §106.352(b)(6). For the same reasons, TXOGA urges TCEQ to also remove the case-by-case requirements for a health effects evaluation in subsection (b)(6) of the proposed standard permit."

The TCAA clearly states the intent of permitting and regulatory actions by the

agency is to "vigorously enforce" regulations to "safeguard the state's air resources from pollution" (THSC, §382.002). To appropriately implement the necessity to issue authorizations for facilities (THSC, §382.003 and §382.0518), the legislature also passed laws giving the commission the ability to generate standardized and streamlined mechanisms. While these mechanisms are developed and implemented, they must continue to protect the public health and welfare. As a part of these mechanisms, the protectiveness criteria established in PBR and standard permits typically includes emission limits with rates in lb/hr and tpy to accommodate protectiveness evaluations and enforceability requirements that consider the ESL guidelines and ambient air standards. THSC, §382.0518 and §382.085 specifically mandate the commission to conduct air permit reviews of all new and modified facilities to ensure that the operation of a proposed facility will not cause or contribute to a condition of air pollution. The review of proposed emissions relies on federal/state standards and contaminant-specific ESLs, respectively, for criteria and non-criteria pollutants. Because of the comprehensiveness of the language in the THSC, ESLs are developed for as many air contaminants as possible, even for contaminants with limited toxicity data. Short-term ESLs are based on data concerning acute health effects, odor potential, and acute vegetation effects, while long-term ESLs are based on data concerning chronic health or vegetation effects. Using these ESLs and emissions dispersion tools, the commission has traditionally confirmed specific hourly and annual emissions will meet these guidelines. Additionally, THSC, §382.085 specifically states that "a person may not cause, suffer, allow, or permit the emission of any contaminant or the performance of any activity that cause or contributes to, or

that will cause or contribute to, air pollution." The term "air pollution" is defined as "the presence in the atmosphere of one or more air contaminants in such concentration and of such duration that: (a) are or may tend to be injurious to or to adversely affect public health or welfare, animal life, vegetation, or property." The NAAQS are standards set by the EPA to protect public health and welfare. The NAAQS include both primary and secondary standards. The primary standards are those which the Administrator of the EPA determines are necessary, with an adequate margin of safety, to protect the public health, including sensitive members of the population such as children, the elderly, and individuals with existing lung or cardiovascular conditions. Secondary NAAQS are those which the Administrator determines are necessary to protect the public welfare and the environment, including animals, crops, vegetation, and buildings, from any known or anticipated adverse affects associated with the presence of an air contaminant in the ambient air. Thus, to meet all expectations, traditional air authorizations focus on lb/hr and tpy of released air contaminants. The staff evaluated the need for standardized maximum pollutant caps with individual registration impacts evaluations for confirmation of compliance with ESLs and standards. Various distances were used for limit development - 1/4 or 1/2 mile to property lines or receptors. Due to the diverse nature of the industry, a single individual hourly value based on highly conservative evaluations was unrealistically low. The particular values for the hourly limits of each PBR level were reassessed to ensure reasonable justification and ability of a majority of sites to meet the limits based on currently reviewed registrations (with limited exceptions).

TPA commented that, "The fact that the PBR proposes requirements stricter than those imposed by federal law triggers the applicability of Texas Government Code, §2001.0225, which defines a major environmental rule as one which: 1) exceeds a standard set by federal law, 2) exceeds an express requirement of state law; 3) exceeds a requirement of a delegation agreement; or 4) adopts a rule solely under the general powers of the agency instead of under a specific state law. Before adopting a major environmental rule, a state agency must perform a regulatory analysis. A regulatory analysis would include an identification of the problem that the rule is intended to address, a determination of whether a new rule is necessary to address the problem, and a consideration of the benefits and costs of the proposed rule in relationship to state agencies, local governments, the public, the regulated community, and the environment. This is just the type of analysis that should have been performed in advance of this rulemaking, as it would have informed the agency of the scope of the problem it was faced with, allowing the agency to make a more considered determination of how to proceed. In addition, when giving notice of the adoption of a major environmental rule, the agency is required to incorporate into the fiscal note a draft impact analysis describing the anticipated effects of the proposed rule, including a cost/benefit analysis, a review of reasonable alternatives, and other reviews."

The commission respectfully disagrees that this rule contains requirements stricter than state or federal law or the evaluation has been insufficient. It is very difficult to respond to this comment due to the very general nature of the assertion that this rule exceeds federal requirements. THSC, §382.085 requires that no person may "cause, suffer, allow, or permit the emission of any air contaminant or the performance of any activity that causes or contributes to, or that will cause or contribute, to air pollution." Under the Federal Clean Air Act, states maintain

wide discretion to "adopt or enforce: (1) any standard or limitation respecting emissions of air pollutants or (2) any requirement respecting control or abatement of air pollution." (Federal Clean Air Act, §116). In addition, under Federal Clean Air Act, §110, the state must implement a program to provide for the enforcement of measures and regulation of the modification and construction of any stationary source as necessary to assure that national ambient air quality standards are achieved. The standards imposed by this PBR and standard permit do not conflict with federal law and seek to further the commission's statutory duty of safeguarding the state's air resources from pollution that the evaluation has been insufficient. The rule as adopted specifically ensures that compliance with state and federal statutes are clearly demonstrated, and are consistent with traditional impacts evaluation methods to provide such a demonstration. This action has included published formal and informal explanations of the scope that the rule is intended to address, determinations of necessity, and careful consideration of appropriate limits and scope.

TPA commented that, "No major environmental rule analysis was conducted in this instance. As such, the proposal of the rule is not in compliance with statutory procedure and the TCEQ is without authority to proceed without having conducted such an analysis. The TCEQ should pause, conduct the requisite analysis, and then proceed with a more considered rulemaking. The Legislature in its wisdom required that a more intense and in-depth analysis be performed by an agency adopting a rule containing provisions that are stricter than federal requirements. That procedure may not be skipped over here."

The purpose of this rulemaking is to increase protection of the environment and reduce risk to public 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 rulemaking does not constitute a major environmental rule, even if it did, a regulatory impact analysis would not be required because the 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 rulemaking does not meet any of the four applicability criteria listed in Texas Government Code, §2001.0225 because: 1) the rulemaking is designed to meet, not exceed the relevant standard set by federal law; 2) parts of the 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 rulemaking is authorized by specific sections of THSC, Chapter 382 (also known as the TCAA).

TXOGA commented that, "It is important to emphasize that the Planned Maintenance, Startups and Shutdowns ("MSS") provisions of the proposed rules cannot permissibly be applied to existing, non-modified facilities operating under current or previous OGS PBRs and standard permits for the same reasons stated above (i.e. to do so would violate the constitutional, statutory, and case law prohibition on retroactive application of regulatory requirements). The proposed revisions as indicated in Exhibit 3 would avoid this pitfall."

The commission did not change rule language in response to this comment. Previously applicable PBR rules at OGS (i.e. PBRs §106.352, §106.512, and associated previous PBR and Standard Exemption versions) did not adequately ensure protectiveness for MSS emissions; impacts reviews for rulemaking of the previously applicable rules did not include impacts reviews for MSS emissions and did not include short-term (i.e., lb/hr) emissions impacts reviews. In previous PBR registration reviews, the commission has seen uncontrolled MSS emission rates of several hundred lb/hr or more of VOCs and has seen MSS emissions rates of 1,000 or more lb/hr of VOCs before controls. Based on the impacts reviews for the new OGS PBR, the commission believes that allowing authorization of OGS MSS emissions retroactively will not ensure protectiveness. The PBR that was promulgated in 1986 did not look at the now understood character and quantity of MSS emissions when writing the rule. The commission cannot clearly demonstrate that MSS is protective and therefore is requiring all MSS activities to be addressed under this version of the rule. The commission agrees that to pass impacts review under the new OGS PBR, MSS emissions may need to be controlled or facilities may need to be upgraded. Although OGS MSS under PBRs was addressed by companies in registration submittals and reviewed by the commission, the commission has determined that based on all the information

available to the commission, protectiveness may not have been adequately addressed.

The PBPA commented that, "Contrary to the justifications that TCEQ provides in its preamble and explanation of the rationale for the new rule, the Agency apparently is ignoring the fact that industry is operating at higher levels of environmental stewardship every year and that there has been a clear trend in this direction for the past twenty or more years."

Devon commented that, "The proposed PBR and standard permit do not account for the ongoing Barnett Shale equipment and emission inventory initiatives. These studies should be used as a guide, or at least considered, during the PBR rulemaking process. Using data from the TCEQ and the Railroad Commission, TXOGA recently published a graph showing the DFW area well count rising exponentially from 2000 - 2009 along with a rising population, overlaid with a plot of eight-hour ozone levels decreasing from 102 parts per billion (ppb) to 86 ppb during that same time span."

PBPA stated "In consideration of the content and tone of TCEQ presentations given to the PBPA in Midland in June, 2010 and state-wide in late August it appears that TCEQ is only willing to consider comments that address relatively minor and arcane aspects of the proposed new rule. The substance of this beast is already a train out of control."

The oil and gas industry appears to be in the midst of a new boom. New

technologies have made hydraulic fracturing an economical possibility and have allowed industry to tap into shale gas that was previously far too expensive to extract. This new boom is the result of technologies and methods that have evolved over the years. And while the technology for drilling wells and producing oil and gas has evolved, the laws governing this industry have not. Texas still operates under the same PBR that it adopted in 1997. The rule adopted in 1997 is a relic from the Standard Exemption List. The Standard Exemption No. 66, which governed Oil and Gas Facilities, became effective in 1986. Essentially, Texas is applying 25 year old rules to an industry where science and technology are evolving on a daily basis. Not only has science and technology allowed us to tap into previously unattainable resources, it has also allowed us to better understand the effect of oil and gas drilling operations has on public health and the environment. Again, the most up to date science and emission detection systems have greatly evolved over the past 25 years. Unfortunately, our laws have not. While the Standard Exemption reflected current science in 1985, it does not reflect current science in 2010. The science of 2010 dictates that the PBR and standard permit be updated in order to be protective of public health and the environment.

PBPA stated that, "Many believe that the oil and gas industry would welcome the opportunity to engage with TCEQ in a collaborative effort to streamline, update and make more effective existing environmental rules and regulations. Our industry has the technical knowledge and means to develop new and improved best management practices, to assist and advise TCEQ in the streamlining (in itself a good thing) of existing rules and regulations, and to adopt regulatory changes that truly improve air quality and that are economically self-sustaining."

The commission has held two stakeholder meetings and two comment periods (one formal and one informal) and has been working with various oil and gas companies and environmental consultants over the last year to build the rule package. Based on additional information submitted, field visits by agency staff, and further research on smaller combinations of facilities, the commission has added subsection (c)(4) to further streamline authorizations and appropriately focus agency and industry resources. The commission is committed to continue working with any companies/individuals to further refine the rule, make changes to it in the future if needed, and issue guidance.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA stated, "The proposed rules appear to have been proposed by TCEQ, to a large degree, in response to the expression of concern by some in the public about alleged impacts of air emissions from OGS in the Barnett Shale area. As detailed in these comments, however, the air quality monitoring and toxicological studies that have been conducted in the Barnett Shale area have demonstrated that OGS operated in accordance with the existing PBR §106.352 or the Oil and Gas Standard Permit in §116.620 are protective of public health and the environment. Thus, while TXOGA understands TCEQ's desire to address legitimate concerns raised by some in the public and specific technical concerns that may have come to light during the agency's own review of OGS operations, TXOGA views the proposed rules as an over-reaction to such concerns. TXOGA believes portions of the proposed rules are legally invalid for the reasons explained in detail in these comments. TXOGA respectfully offers these comments in order to provide TCEQ with alternative PBR and standard permit language that would make the proposed PBR and proposed standard permit more workable for the agency and for regulated entities, and to cure many of the legal flaws associated with the proposed PBR and proposed standard permit. Thus, TXOGA's comments are intended to be a constructive approach to addressing what TXOGA understands to be TCEQ's rationale for developing the proposed rules."

The commission did not change any rule language as a response to this comment. The need to update this rule did not originate with the increased activity in the Barnett Shale region. The commission recognized that the rule was inadequate much earlier and has "under development" potential revisions for over 5 years. Before 2005 even further work was done to attempt to update this rule. The rule is written to address ongoing important issues that are applicable to all oil gas sites across the state. The increased exploration and production in the Barnett Shale added urgency to the implementation of regulatory updates the commission has considered for a significant period of time.

Devon has "made this effort to provide the TCEQ with a set of comprehensive comments including both a generalized, high-level set of overarching concerns regarding the proposed rules in addition to addressing specific items that may be considered either unachievable for operators or inefficient in achieving actual emission reductions." TPA hopes that "substantial revisions are made to the PBR. Of particular concern to the TPA are four issues that must be addressed to ensure a clear and implementable PBR if it stays substantially the same."

The commission appreciates the detailed comments provided and has used this

information to refine and clarify the PBR into a reasonable, effective streamlined and protective authorization.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Many of the proposed requirements in the proposed PBR and standard permit are practically or economically infeasible and/or are arbitrary or unreasonable in light of the scientifically available information demonstrating that OGS do not cause a public health concern."

The commission has made efforts to make this rule no more complex than it has to be, but at the same time not oversimplified. The commission has made changes to make sure that the rule achieves that goal.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko "Requests a concise statement for and against adoption if TCEQ adopts the proposed rulemakings, pursuant to the APA, TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requests that TCEQ issue a concise statement of the principal reasons for and against adoption, including reasons for overruling considerations against adoption urged by TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko in these comments."

The commission is including a reasoned explanation and response to comments on this rule as part of the adoption of the new PBR.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented that, "Interested persons have not been provided with a reasonable opportunity to submit data, views or arguments as required by §2001.029 of the Administrative Procedure Act TXOGA firmly believes that TCEQ has not provided regulated entities and other interested persons with a reasonable opportunity to submit data, views and other arguments for this TCEQ regulatory initiative. The amount of time afforded by TCEQ for TXOGA and other interested persons to submit comments relating to TCEQ's proposed PBR and proposed standard permit is not the reasonable amount of time required by the APA. Although 65 calendar days (and 47 business days) may be a reasonable amount of time to review and comment on a typical TCEQ rulemaking, TCEQ's proposed rules are extremely complex and novel. A longer comment period than has been provided by TCEQ is necessary because of the complexity of the legal issues raised by the proposed rules, the need to both legally and technically analyze the complex proposed regulatory scheme, the need to obtain experts to perform such analysis, and the need to prepare detailed comments relating to the proposed rules. Further, there is no legally required federal or state statutory mandate or deadline to adopt a new PBR or standard permit. Thus, TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko fails to understand TCEQ's rush to adopt the proposed rules, particularly in light of the TCEQ's own health impacts analyses in the Barnett Shale area that have demonstrated that the oil and gas operations in that area are not creating a significant negative impact on public health or the environment. TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko can conjure up no reason to believe that there would be any harm in providing TXOGA, Devon, GPA, Noble, ExxonMobil, Anadarko, and other interested persons with a more robust opportunity to comment by either extending the comment period or by republishing the proposed PBR and the proposed standard permit for further comment. And, unlike the proposed PBR and the proposed repeal of the existing PBR, there is no timeframe by which TCEQ must act on the proposed standard permit. Thus, TCEQ has a great deal of flexibility in extending the comment period on the proposed standard permit."

TIPRO appreciates the extension of the comment period to October1, 2010 but is concerned that the schedule adoption date of the rule has been moved forward by 1 month. The extension of the comment period and the advance of the scheduled adoption date decreases the agency review time of comments by 6 weeks. This leads one to think that the submitted comments are an exercise in futility and carry little or no weight as TCEQ is dead set on expediting the process regardless of the content of the comments. While this may not be the case, it is the perception one garners for the shortening of the time frame this late in the process. The primary question that has yet to be answered to TIPRO's satisfaction is why must this proposal moved forward so quickly. The TCEQ staff reply was two-fold. The first reply was that development of these rule changes was initiated years ago and input from industry was solicited, but that little to no response was received. Even if this claim is taken as fact, industry's lack of response in the past does not give the agency carte blanche to charge forward with promulgation of rules that will kill jobs in the energy sector. Agency staff's second reply to the timeline question is that the TCEQ has an agreement with EPA to account for MSS emissions in PBRs by January 2012. In order to allow ample time for compliance, this means the rule changes must be completed by January 2011. TIPRO maintains that the TCEQ has the discretion to move forward only with the promulgation of rule changes incorporating MSS emissions into PBRs, and can wait to make any further changes to the rule. Should data gathered regarding industry's impact on air quality necessitate additional regulation, TCEQ could move forward at that time.

PBPA requested that "the deadline for comment be extended beyond October 1, 2010. They also stated It would have been, and would be, far better for TCEQ to work directly with industry and its technical assistants and legal representatives to craft a new rule that would be to the benefit of all. The State should therefore put aside this proposed new rule while a TCEQ-industry task force is created to craft an effective rule within a reasonable time frame. Everyone would learn and benefit from such an exercise, and all Texans would be far better served."

The commission first began looking at updating requirements in 2003. Additionally, in 2004 comments were received on the standard permit from TXOGA and other associations. In 2005, the commission issued a detailed background document and proposal. After holding 6 meetings throughout the state, additional information and feedback was requested from industry. In the last year, the commission has held two stakeholder meetings and two comment periods (one formal and one informal) and has been working with various oil and gas companies and environmental consultants over the last year to build the rule package. The commission has further extended the period for consideration to January 26, 2011 to allow sufficient time for all parties to review available information as well as provide the opportunity to resolve remaining concerns. The commission is committed to continue working with any companies/individuals to further refine the rule, make changes to it in the future if needed, and issue guidance.

TXOGA also disagrees that the "Proposed rulemakings do not constitute major environmental rules based on the applicability requirements listed in Texas Government Code, §2001.0225(a). TCEQ asserts in the preamble that the proposed PBR is designed to meet, not exceed, the relevant standards set by federal law, and that the proposed PBR would "reference the many new federal standards which have been promulgated by EPA (See 35 TexReg 6968 (August 13, 2010))." However, despite TCEQ's assertions, several of the technical requirements in the proposed PBR exceed any standards set by federal law and are not specifically required under state law. This is another reason that the proposed PBR falls under the definition of major environmental rule" under Texas Government Code, §2001.0225(a)(1) and triggers the requirement for a cost/benefit analysis and a draft regulatory impact analysis. Specifically, the following technical requirements in the proposed PBR exceed specific federal New Source Performance Standards ("NSPS") that are not expressly required by state law: (i) the heat input limits go beyond the requirements of NSPS Dc (See 40 CFR Part 60, Subpart Dc (regarding Standards of Performance for Small Industrial- Commercial-Institutional Steam Generating Units)); The fuel monitoring requirements for heaters go beyond the requirements of NSPS Dc (See 40 CFR Part 60, Subpart Dc (regarding Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units)); (iii) The fugitive monitoring requirements go beyond the requirements of 40 CFR 60 NSPS KKK as there is no threshold for Volatile Organic Compound ("VOC") monitoring (See 40 CFR Part 60, Subpart KKK (Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants)); (iv) The emissions requirements for engines go beyond the requirements of 40 CFR 60 NSPS JJJJ (See 40 CFR Part 60, Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines)); and (v) The emissions requirements for several categories are lower than those required under federal law (e.g., the BMPs are different that those required of 40 CFR 60 NSPS JJJJ (See 40 CFR Part 60, Subpart JJJJ (Standards of Performance for

Stationary Spark Ignition Internal Combustion Engines)) engines, the tank and vessel color requirements go beyond the requirements of NSPS Kb (See 40 CFR Part 60, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984))."

TXOGA also commented that, "TCEQ admits that "parts of the proposed rulemaking are directly required by state law" (emphasis added), which leaves open the question of which other "parts" of the proposed rulemaking are not expressly required by state law (See 35 TexReg 6968 (August 13, 2010)). Under Texas Government Code, §2001.0225(a)(2), a proposed rule that exceeds an express requirement of state law triggers a draft regulatory impact analysis and cost/benefit analysis unless there is a requirement imposed by federal law. Since TCEQ admits there are "parts" of the proposed PBR that exceed an express state law requirement, TCEQ must perform the analysis required under Texas Government Code, §2001.0225 for those parts of the rules, unless TCEQ can identify the federal requirements which TCEQ is attempting to meet. No such identification of federal requirements has been made."

TXOGA stated that, "Texas law requires a heightened scrutiny for the promulgation of major environmental rules. As stated in the Senate Natural Resources Committee Report on Texas Government Code, §2001.0225, "{t}he heightened scrutiny approach would be applied only to the environmental regulations that are not specifically required by federal law, a federally-delegated program agreement or an express requirement of state law. Obviously, if the agency has no discretion about whether to adopt regulations, it should not be required to prepare a heightened scrutiny document." (emphasis added) (See The Senate Natural Resources Committee, Interim Report to the 75 Legislature, Use of Cost Benefit Analysis in Environmental Regulation, September 1996, p. 8). It is undisputed that the TCEQ has very broad discretion to promulgate a rule authorized by statute which establishes standards that are protective of public health and the environment. However, in this case, the exercise of TCEQ's broad discretion in promulgating the proposed PBR triggers the legislative requirement to perform a regulatory impact analysis under Texas Government Code, §2001.0225 since the proposed PBR exceeds the federal standards and is not authorized by a specific state requirement. TXOGA stated that since Texas Government Code, §2001.0225 of the APA applies to the proposed rulemakings, the reasonableness of TCEQ's approach to regulating OGS must be properly debated and assessed through the regulatory analysis of major environmental rules. This is not to say that the agency does not have the general authority to propose and ultimately to adopt a proposed PBR and proposed standard permit if they meet all applicable legal requirements (e.g., is in harmony with the statutory authority do so and is not retroactive), but simply that the agency must follow the procedures set out in Texas Government Code, §2001.0225 to ensure that the rules result in the "best combination of effectiveness in obtaining the desired results and of economic costs not materially greater than the costs of any alternative regulatory method considered (See Texas Government Code, §2001.0225)." Since TCEQ proposed these rules without quantifying the costs and benefits of the rules or describing reasonable alternative methods for achieving the purpose of the rule, as required by Texas Government Code, §2001.0225, the proposed PBR is invalid."

TPA commented that, "There is no need to take a radical new approach to the PBR such that a simple, easy-to understand rule is cast aside and replaced with a 45-page document that is extremely complicated, is difficult to interpret, imposes a broad array of detailed control requirements that should not be applied to insignificant sources, involves an inordinate amount of case-by-case review, and in some instances even requires entities to obtain approval from agency staff prior to undertaking a new project. Nor is it justification for the imposition of requirements that would be stricter than those imposed by federal law and that would unfairly single out the Texas oil and gas industry for treatment that would be stricter than that accorded to other industries in the State. Given current economic difficulties and the absence of any demonstrated health threat from oil and gas facilities, this is no time to rush into a wholesale re-write of the rules governing oil and gas production. The imposition of a new, untested, and potentially unworkable regulatory program in the Texas oil and gas industry is unwarranted, and it could have a severe negative impact on the oil and gas sector in this State and therefore on the budget and economy of the State. We would be very interested in working with the agency to develop the existing proposal into one that will result in requirements that assure continued protection of public health and the environment yet provide ease in implementation and certainty in compliance and enforcement."

Devon Energy Corporation stated that, "Section 5382.01596 of the Texas Clean Air Act (TCAA) authorizes TCEQ to adopt permits by rule for types of facilities that will not significantly contribute air contaminants to the atmosphere. Including annual and hourly emission limits, protective limits, best management practices and extremely onerous and prescriptive sampling, monitoring and recordkeeping requirements in the proposed PBR for OGS goes far beyond what is required in any other current PBRs. In addition, most of the provisions in the proposed PBR are very similar to those in TCEQ's proposed oil and gas standard permit. Finally, as referenced in these comments and TXOGA's comments, many requirements in the proposed PBR are as stringent as provisions typically found in TCEQ individual permits for major nonattainment area sources. By proposing an OGS PBR that goes far beyond the requirements of any other current PBRs and that, in effect, erases the distinction between PBRs, standard permits and individual permits, TCEQ has not complied with its legislative mandate to adopt a PBR tailored to and appropriate for, insignificant emission sources."

Kinder Morgan "appreciates the opportunity to comment on the proposed revisions to the Oil and Gas PBR §106.352 and Standard Permit. Kinder Morgan affiliates operate in the Oil and Gas Industry and will be substantially affected, in a negative way, by this major change in how PBRs are structured and applied to this industry. In many cases, the proposals are more stringent than the requirements in the areas around the country designated as nonattainment with the National Ambient Air Quality Standards (NAAQS). At the same time, some of the proposals have the potential to raise additional operational or safety concerns, in addition to the significant financial impacts. We do not believe that the Commission intended these consequences because the Commission wants to be no more stringent than federal regulations. Please note that as drafted, this proposed revision subjects the oil and gas industry to more onerous requirements than other similar industries which do not use PBR §106.352 but which use another PBR. This proposed PBR revision is overly prescriptive and deviates from historical PBR philosophy in that until now if a "facility," as that term is defined in Texas, could qualify for a PBR by staying below the emission thresholds in §106.4, a PBR could be used. As currently proposed, the PBR could no longer be used at the "facility" level and an oil and gas site (OGS) would not only have to meet these thresholds but also install emission controls even though there is no modification or other trigger to install controls under existing clean air quality requirements. This is inapposite to all existing PBR and Clean Air Act requirements."

The commission disagrees that this PBR contains requirements stricter than state or federal law or that the evaluation has been insufficient. The PBR as adopted specifically ensures that compliance with state and federal statutes are clearly demonstrated, and are consistent with traditional impacts evaluation methods to provide such a demonstration. This action has included published formal and informal explanations of the scope that the PBR is intended to address, determinations of necessity, and careful consideration of appropriate limits and scope. If an applicant can establish that their facilities and operation at their location are unique and should not need to meet the emission limitations of this standard permit, they may apply for a case-by-case NSR permit.

One of the commentors raised concerns about several specific proposals, including: 1) the heat input limits for small boilers; 2) fuel monitoring requirements for heaters; 3) fugitive monitoring requirements; 4) emissions requirements for engines; 5) BMPs for engines; and 6) tank and vessel color requirements. The commission carefully evaluated these issues as described in the following:

1) Small boiler NSPS requirements in NSPS Subpart Dc has no applicable requirements for gas fired steam generating units which are the type of units expected at OGS. The proposed PBR and standard permit have no heat input requirements for any steam generating units other than a requirement to keep

records of fuel use and hours of operation only if the applicant claims less than 100 percent utilization of the facility. Without evidence of actual usage, an applicant, the state, and the public would have no way of determining how much a facility operated during any given time period and whether an applicant abided by a certified claim of less than 100 percent utilization. As this PBR and standard permit are part of the minor NSR program approved in Texas' SIP, this condition is expressly required by federal rules in that permits and their associated emission limits must be practically enforceable;

2) Fuel monitoring for heaters as compared to NSPS Subpart Dc shows that the federal rules have no applicable requirements for gas fired steam generating units which are the type of units expected at OGS. The proposed PBR and standard permit have no requirements for any steam generating units other than a requirement to keep records of fuel use and hours of operation only if the applicant certifies less than 100 percent utilization of the facility. Without evidence of actual usage, an applicant, the state, and the public would have no way of determining how much a facility operated during any given time period and whether an applicant abided by a certified claim of less than 100 percent utilization. As this PBR and standard permit are part of the minor NSR program approved in Texas' SIP, this condition is expressly required by federal rules which require permits and their associated emission limits to be practically enforceable;

3) Fugitive monitoring requirements vary from quarterly physical inspection to

standard LDAR and enhanced LDAR, depending on potential of emissions. Basic fugitive monitoring is not addressed in NSPS Subpart KKK and is necessary under the PBR and standard permit to ensure that leaking components are identified and fixed prior to substantive emissions being released into the atmosphere. The minimal effort required for this inspection to prevent unnecessary emissions from equipment failure is a reasonable expectation to ensure proper operation of facilities. The LDAR requirements under the standard permit are long-standing BACT, which must be used by standard permits. The fugitive monitoring requirements have several specific thresholds for VOC monitoring in Table 9 of subsection (m), most specifically exempting monitoring for components where the VOC in the component has a vapor pressure less than 0.044 psia at 68 degrees F or the maximum process operating temperature. This is more stringent than the very old Subpart KKK, but is consistent with long standing BACT for fugitive monitoring in permits;

4) Engine emission limits in 40 CFR Part 60 NSPS JJJJ only applies to engines manufactured in 2007 or later. This represents a very small percentage of the engines the commission regulates or would expect to permit under the proposed PBR in the immediate future. The proposed PBR incorporates Subpart JJJJ and adds emission standards to the engines not regulated by that subpart. If the commission only relied on Subpart JJJJ, all engines manufactured before 2007 would have no emission standard. This would represent a serious backsliding on current control requirements since §106.512 governed OGS engines for at least 20 years. The proposed PBR applies the rich burn engine technology deemed

acceptable in Subpart JJJJ to the vast majority of rich-burn engines not regulated by that Subpart. Rich-burn engines greater than 500 hp would be expected to have an incremental gain in control efficiency by January 1, 2020 under the revised PBR which is not unreasonable to expect. BACT requires more strigent, immediate limitations and upgrades sooner, however under the standard permit, the commission recognizes the challenges of upgrading the numerous engines. Therefore the commission has allowed a scheduled approach to upgrading engines to BACT under the standard permit.

5) BMPs for engines were reviewed against 40 CFR Part 60 NSPS JJJJ which only applies to engines manufactured in 2007 or later. This represents a very small percentage of the engines the commission regulates or would expect to permit under the proposed PBR in the immediate future. The proposed PBR incorporates Subpart JJJJ and adds emission standards to the engines not regulated by that subpart so that all spark-ignited engines have an emission standard. If the commission only relied on Subpart JJJJ, all engines manufactured before 2007 would have no emission standard. This would represent a serious backsliding on current control requirements since §106.512 governed OGS engines for at least 20 years. The BMPs in Subpart JJJJ are in addition to the numerical emission standards in that Subpart. The commission took the BMPs of Subpart JJJJ into account when changing the proposal in response to comments. Recordkeeping required by Subpart JJJJ will also be applicable to the PBR to minimize duplication of effort. No engine that has an emission standard under federal law was required to meet a lower emission limit in the PBR. The PBR fills in the gaps

in the federal standards. BACT requires more strigent, immediate limitations and upgrades sooner, however under the standard permit the commission recognizes the challenges of upgrading the numerous engines. Therefore the commission has allowed a scheduled approach to upgrading engines to BACT under the standard permit; and

6) The requirements in the PBR for tank and vessel color have been revised to be optional for the PBR and are provided only as a standard for applicants to use if they wish to claim a reduced percentage of tank emissions in order to meet impacts limitations. This is listed under BMP to ensure that all equipment is maintained in good working order and operated according to design. The conditions set forth in the BMP section are necessary to ensure that equipment on-site is maintained as intended and not left to deteriorate. If this equipment was left to deteriorate beyond design parameters then the calculated emissions from this equipment could not be accurate. For standard permits, new and changed tanks and vessels which have a potential of 5 tpy VOC are required to meet color requirements, consistent with over 20 years of BACT determinations.

In general, the purpose of this rulemaking is to increase protection of the environment and reduce risk to public 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 rulemaking does not

constitute a major environmental rule, even if it did, a regulatory impact analysis would not be required because the 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 rulemaking does not meet any of the four applicability criteria listed in Texas Government Code, §2001.0225 because: 1) the rulemaking is designed to meet, not exceed the relevant standard set by federal law; 2) parts of the 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 rulemaking is authorized by specific standard permits of THSC, Chapter 382 (also known as the TCAA).

There are many required records to be kept to demonstrate compliance with the PBR. The recordkeeping is required by §106.8, but to ensure practical enforceability the commission has stated what records need to be kept for demonstrating compliance under this PBR. However, in any instance in which records are being kept for other purposes, but show the same information, this will be acceptable to the commission. This will require no additional paperwork,

man-hours, or time to demonstrate compliance. Although this rule is longer than the previous PBR, in order for the commission to allow maximum flexibility for this diverse industry, the PBR had to be expanded for this flexibility. The commission has addressed the cost of the PBR package in previous response to comments.

ETC commented that, "There are provisions in the proposed PBR that are more restrictive than those imposed by federal law, thereby creating inconsistencies with the federal requirements. These inconsistencies will lead to unnecessary confusion during the implementation and enforcement of the proposed PBR. Examples of PBR requirements that are inconsistent with federal law include the following: (i) The PBR would require a demonstration of compliance with NAAQS for existing unmodified minor sources; whereas the federal Clean Air Act only requires a NAAQS compliance demonstration for new construction or modifications at PSD major sources; (ii) The PBR would require an impacts review on unmodified sources at a site where there are new or modified sources; whereas federal PSD/NSR rules only require an impacts review of the "project." Unmodified sources at the site are not considered part of the project and are not subject to emissions impacts review under federal law; and (iii) The PBR would use lbs/hr figures as a basis for determining whether a site would be subjected to registration and possible pre-approval requirements under Level 1 or Level 2; whereas federal rules under Title V and the PSD program base similar determinations on the use of less onerous tons-per-year (tpy) figures."

NAAQS are federal standards, and must be met whether or not a demonstration is required. As stated in a previous response, the state must have a program that

ensures all stationary sources, not just major sources, protect or maintain the NAAQS. The PSD program addresses major sources and major modifications to existing major sources. The commission, through the TCAA, develops and maintains a minor source program to meet the federal requirement. In addition, the PSD program only applies to certain regulated pollutants. The TCAA requires the commission to evaluate all air contaminants. The commission has determined that it is appropriate to consider site-wide emissions rather than simply project emissions to determine the environmental impact as air emissions that occur from previously authorized and new sources together contribute to ambient air quality. The commission has also determined that short-term emission rate limits are necessary in the rule and that the short-term limits are not just a conversion of the tpy limits for various reasons, but accurately represent the hourly releases which occur from an authorized site to demonstrate impacts and provide a direct correlation to the hourly ambient standards in state and federal law.

TXOGA stated that, "The state laws cited by TCEQ as the basis for the proposed PBR in the preamble are Texas Water Code, §5.103 and §5.105 (concerning general powers and rulemaking in general), and Texas Health and Safety Code, §§382.017 (general policy and rulemaking), 382.002 (policies and purposes), 382.011 (General Powers and Duties), 382.012 (State Air Control Plan), 382.051 (general permitting authority), 382.05196 (Permits by Rule), 382.0518 (generally establishing regulations for facilities that have the potential to emit), and 382.057 (exemptions from permitting). Clearly, all of the cited state statutory authority relates either to policy or general powers and duties of TCEQ, but none comes close to being an "express requirement of state law" to adopt these particular, specific technical requirements for the oil and gas industry which would be imposed by the proposed PBR."

The commission has not made any changes based on the comment. There is no specific statute which requires a PBR to be developed for the oil and gas industry, or one with specific and certain requirements. If such a law is passed, the commission will actively pursue its implementation. Until such time, technical and administrative updates to existing PBRs follow a standardized process which identifies facilities, operations, planned MSS, typical controls, impacts and protectiveness, and practically enforceable limits consistent with minor source authorizations in Texas.

PBPA stated "Despite industry objections, it appears that you intend to move forward in implementing this rule. Therefore, the PBPA offers to participate and collaborate with TCEQ in the development of "Guidance Documents" to implement the technical specifics of the proposed new rule. This would be to ensure that the criteria and measures that are stipulated in the new rule are addressed using the most cost-effective and result-effective technologies and approaches. This would encourage industry to bring forward their best and brightest talents to maximize the desired end of the new rule (substantially improved air quality). Such collaboration would also ensure that no effort would be spared to find emissions control technologies and best operational practices that have a positive economic return and are thus economically self-sustaining in their own right. TCEQ create three, focused work groups in collaboration with oil and gas industry professionals and other stakeholders to address the general and specific issues concerning economics, emissions inventory and emission controls.

This effort need not impose interminable delays to TCEQ's required time frame for updating their oil and gas air quality regulations. Carefully and openly selected panels of experts can accomplish their work over the course of a few months."

The commission understands the concerns and is very conscious of fiscal responsibility and useful tools. As a part of the initial implementation of this revised PBR, the commission is committed to providing various opportunities for companies, trade associations, and the general public to provide input on various registration and compliance issues. The commission has held two stakeholder meetings and two comment periods (one formal and one informal) and has been working with various oil and gas companies and environmental consultants over the last year to build the rule package. The commission has further extended the period for consideration to January 26, 2011 to allow sufficient time for all parties to review available information as well as provide the opportunity to resolve remaining concerns. The is committed to continue working with any companies/individuals to further refine the rule, make changes to it in the future if needed, and issue guidance.

The PBPA stated that, "It would have been, and would be, far better for TCEQ to work directly with industry and its technical assistants and legal representatives to craft a new rule that would be to the benefit of all. The State should therefore put aside this proposed new rule while a TCEQ-industry task force is created to craft an effective rule within a reasonable time frame. Everyone would learn and benefit from such an exercise, and all Texans would be far better served."

The commission has been working informally with industry throughout the state since 2004 on updates and possible requirements, including several stakeholders meetings around the state and locally in Austin. The commission is also committed to continuing to work with all interested stakeholders in developing consistent, easy-to-understand tools for emission estimates, registrations, and compliance demonstrations.

Senator Davis stated "the key to responsible drilling in Barnett Shale is increased monitoring, enforcement and open communication with the public. We must have reliable, trustworthy and transparent data to ensure that the state of Texas is protecting the health and safety of our families living in the midst of gas drilling."

The commission agrees with the comment.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated, "The Legislature authorized TCEQ to promulgate standard permits for new or existing similar facilities if the TCEQ finds, among other things, that the standard permit will be enforceable and TCEQ can adequately monitor compliance.51 The overall, general intent behind the legislation authorizing the issuance of PBRs and standard permits was founded on permitting flexibility. Although the legislative intent was for PBRs and standard permits to initially apply to grandfathered facilities, the plain language of the statute indicates that the legislative intent was also that PBRs and standard permits continue in existence as a more flexible method of authorization for new and other existing facilities than the traditional "restrictive pre-construction permit program that is far more strict than most permitting programs in other states. With regard to standard permits in particular, the legislative record indicates that standard permits were intended to provide "more flexibility" to encourage existing grandfathered facilities to obtain an authorization, and to allow new facilities to obtain coverage under the new, more "flexible" approach as well. The legislative record, therefore, clearly indicates that the Legislature granted TCEQ with the authority to promulgate PBRs and standard permits as a more flexible mechanism of authorization when compared to an individual permit. Furthermore, although the Legislature created the authority to promulgate PBRs and standard permits to address the grandfathered facility issue, the Legislature clearly intended for new and existing facilities to have the option of utilizing PBRs and standard permits as a more flexible authorization even after the grandfathered facility issue was resolved. The proposed PBR and proposed standard permit, however, would impose onerous and prescriptive requirements on an OGS that are more akin to requirements that are applicable to facilities that must obtain state and/or federal NSR permits. No other PBR or standard permit comes close to being as onerous, prescriptive, or complicated as the proposed PBR and proposed standard permit would be. Moreover, TCEQ's own air monitoring and toxicological studies (as detailed above) have demonstrated that OGS operating in accordance with the TCEQ's current PBR or standard permit for OGS are making insignificant contributions of air contaminants to the atmosphere.

ETC commented that the proposed PBR would create excessive reliance on case-by case-review. For example, the proposed impacts reviews and modeling demonstrations would drive site-specific emission limits. In addition, the requirement in the Level 2 PBR relating to preconstruction approval would create a situation where agency judgment would have to be exercised on an ongoing, particularized basis. In such an instance, there would be little or no difference between the process used under the PBR and that used in traditional case-by-case permitting. The inclusion of provisions that are not self-executing but rather require the exercise of judgment by TCEQ staff (and occasionally, pre-approval by TCEQ) would add confusion, uncertainty; and slow the permitting process. This defeats the very purpose of a PBR and, in the case of the Level 2 preconstruction approval it would have the potential to create an unnecessary impediment to oil and gas production, which could significantly harm the Texas economy."

The commission agrees in general with the statements of the commenter. The mechanisms of PBR and standard permits are more streamlined than case-specific permit reviews, and continue as such under the new PBR. The PBR does not require: public notice (which would add months to each review and cost up to $5,000); BACT (many controls which are optional in the PBR would be mandatory); a case-specific set of special conditions and recordkeeping requirements; and is a mandatory preconstruction authorization. To provide this flexibility, the requirements must be protective and cover all potential emissions and sources. Further, PBRs must be insignificant, comply with all applicable state and federal standards, rules, requirements, and limitations. The PBR accounts for all of these factors, and its complexity ensures insignificance of these facilities. The commission also recognizes that since permitting is done on a worse-case scenario, it would expect to see no exceedances of a criteria air contaminant from

monitoring, since normal operation would be less than the permitted allowance.

Encana requests the "TCEQ to consider the economic impact that the industry will incur if the implementation of quarterly performance test for each engine and testing after a sensor replacement or major maintenance becomes final in the rulemaking. Encana believes that a good maintenance plan and semi-annual or annual performance testing should be sufficient to ensure the proper operation of the engines. Encana would like the TCEQ to consider a phased approach to engine testing incorporating engine size and location." The letter from Encana has a table of an example that "the TCEQ should consider."

The commission has evaluated the economic impact of the new PBR OGS rule. The commission changed engine quarterly testing for all OGS under PBR to semiannual testing for only OGS subject to Title V requirements. The semiannual testing of engines is expected to cost about $45.00 for stain tubes for each semiannual test and require about 20 minutes of labor time per each semiannual test. Increased labor cost will vary based on the hourly cost of labor. The use of stain tubes requires minimal training, and training costs for such use are expected to be minimal. Labor costs are expected to be internal costs not costs due to consultants or testing companies. The increased recordkeeping costs are expected to be minimal. Otherwise, requirements for engines were not changed in the new PBR OGS rule in comparison to PBR §106.512, except for changes that matched federal rule requirements. The commission did not consider changes to match federal rule requirements to cause increases in cost due to the new OGS PBR rule

itself. Due to these changes, engine costs are expected to decrease qualitatively overall. Therefore, there are no other cost increases associated with engines.

PBPA commented that, "In tandem with the economic analysis called for above, that TCEQ similarly collaborate with industry environmental engineers and scientists to develop and coordinate on emission estimation methodologies which are robust, efficient and cost-effective. In lowering emissions Thresholds for VOCs, H_2S and S02 so drastically (and beyond that which is required in other oil and gas producing states) TCEQ is imposing tremendous difficulties for sour oil/gas production facilities, due to the difficulty in reducing VOCs and H_2S without exceeding the SO_2 emission threshold of 15 tons/yr. The requirement for painting storage tanks a reflective color is also onerous and, in many cases, unsightly. We believe that there needs to be reasonable flexibility so that the total emission profile from a facility can be calibrated according to the produced oil/gas characteristics, taking into account logistical and economic considerations. We therefore propose that TCEQ work with industry engineers to develop emission control strategies which optimize air quality benefits while taking into account, and making reasonable allowance for, economic and logistical considerations."

The commission considered this comment along with others, and the economic impact associated with this rule package has been assessed. The thresholds for the various pollutants have been updated based on refined modeling parameters. All controls in the PBR are voluntary. The light tank paint color is what the commission recommends with this rule as a simple way to reduce the amount of air emissions from tanks; it is not a requirement.

Registration and Scope of Authorization

TPA commented that, "Vague provisions in the proposed PBR should be clarified. To be useful and effective, a PBR must be clearly and precisely drafted and its terms must be free from confusion and issues of interpretation. Yet the proposed PBR fails to provide certainty even on fundamental matters such as which facilities would be covered by the new rule. Nowhere in the rule is there a precise definition of key terms such as "production," "potential to emit (PTE)," "project," or "operationally related.""

The commission partially agrees with this comment and has included various clarifications and additions of terms to ensure understanding and transparency when using this PBR. Where Terms that are of common understanding and their use is already outlined in TCEQ or EPA guidance, the rule has not been updated.

TXOGA requested that "registration, certification, represented, and authorization need to be clearly defined since they are used in various places throughout the regulation and it is unclear what each means."

The commission partially agrees with this comment and has included various clarifications and additions of terms to ensure understanding and transparency when using this PBR. Where Terms that are of common understanding and their use is already outlined in TCEQ or EPA guidance, the rule has not been updated.

Pioneer commented that, "At the Stakeholder Meeting held on August 31, 2010, staff mentioned that drilling and related activities are not covered by this PBR §106.352. Please clarify this exclusion in the final rule and specifically detail that drilling, workovers, and completions (including freeing) are not covered by this PBR. Please also clarify the scenario if a workover rig is brought in after a well has been producing for a period of time under the new PBR. Next, well tests vary in duration and are currently regulated by the Texas Railroad Commission. Generally it is unknown how long a well test will last until it is conducted. Furthermore, they often last up to 1 week which is still a temporary source of emissions. Sometimes, as in Pioneer's Permian Basin operations, a well test can be intermittent and extend over a period of weeks or months in order to understand the nature of the producing environment. For example, a well test could be conducted for a 24-hour period once per week for the initial 3 months. Pioneer requests that Intermittent testing, that may exceed 72 hours in total, also be recognized in the final rule as a temporary source of emissions."

The commission partially agrees with this comment, but has not changed the rule in response. The terms used by the commenter do not have consistent, common meaning to regulators, the general public, or even the oil and gas industry. It is not the commission's intent to have this PBR authorize emissions from any activity excluded under the TCAA, specifically mining (referred to here as drilling) and limited duration well tests. The types of activities which are likely included under these terms are expected to include "workovers." However, even if well tests typically can take a week or more, the current statute only excludes them for 72 hours, and regardless of their temporary or intermittent status, are otherwise required by law to obtain an authorization.

Devon commented that, "The language concerning the definition of a facility implies that a well test or drilling activity lasting 72 hours or more is considered a stationary source and would be a covered source in the proposed PBR. These activities are short in duration, far less than 12 months, which is the typical time used to establish a stationary source. Further, emissions from temporary oil and gas facilities are covered under §106.353 and allows for a period not to exceed 90 days where the purpose is "to test the content of a subsurface stratum believed to contain oil gas and/or establish the proper design of a permanent fluid-handling facility." Therefore, the language in subsection (b)(1) of the PBR should read, "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, workovers, completions, or well tests are not considered facilities."

The commission respectfully disagrees with this comment and has not changed the rule in response. The TCAA clearly defines a facility and specifically includes well testing after 72 hours. There is also no state or federal statute which holistically exempts temporary facilities or sources from requirements of air permitting. In fact, there is only one exception to a temporary facility being considered a stationary source, and that EPA policy is only for off-road engines at a specific location less than 12 months. No other temporary or transitory facility is exempted from obtaining an authorization under Texas air permitting rules and laws. The commission does note however, the precedent of §106.353 and has incorporated the requirements of this PBR §106.353 into the revised registration and notification requirements of this PBR.

EDF commented that, "The final rule should incorporate emissions from natural gas well activities into authorizations in order to adequately protect public health. Otherwise, the TCEQ should identify any statutory or jurisdictional basis for the TCEQ to exempt natural gas wells from coverage under the PBR or standard permit. Given the discrete yet predictable nature of emissions from natural gas well activities like completions, re-completions, workovers, and unloading, one approach to incorporating the resultant emissions would be to treat them as planned MSS emissions."

It is not the commission's intent to have this PBR authorize emissions from any activity excluded under the TCAA, specifically mining (referred to here as drilling) and limited duration well tests. The types of activities described by the commenter (completions, re-completions, workovers) all involve actions taken by operators in the well or "down hole" and are considered part of the drilling process, and therefore beyond the jurisdiction of the air permits program.

Mayor Calvin Tillman of DISH commented that, "The rules should include all equipment regardless of ownership."

The commission has not changed the rule in response to this comment. The TCAA clearly limits the authority of air permitting to the owner or operator of facilities. The laws and regulations on both the state and federal level clearly limit the jurisdiction of the commission in this regard.

Targa commented that the words "or interest" need to be removed from the definition. Anything beyond common operator will not work in an industry full of joint ventures and complicated contracts. The word "interest" is not included in the definition of site in Title V (see the definition in Chapter 122).

The commission agrees with this comment and has revised the language of subsection (b)(3)(B) to be consistent with the definitions in 30 TAC Chapter 122.

Pioneer requested that the commission define what is meant by "interest" in the rule or preamble to provide clarity for future reference. It is common in the oil and gas industry that two or more companies have control over different equipment at an OGS. For example, often metering and pigging facilities may be set by a third party on Pioneer locations. The rule or preamble must clarify how ownership is determined at an OGS.

The commission agrees with this comment and has revised the language of subsection (b)(3)(B) to be consistent with the definitions in 30 TAC Chapter 122. The commission also clarifies that the responsible permit holder is the operator with daily control.

EDF supported the ability of the commission to deny an application for good cause. There are many scenarios foreseeable where some discretion would be warranted to avoid having to issue an automatic approval. These include site-specific considerations such as adjacent land uses, an applicant's compliance record, complaints, and the legal burden that would be placed on the agency to pull a permit after the fact.

This subsection has been revised to provide the specific circumstances for which the commission may deny a PBR. The revised language states that the reasons the commission may deny a PBR include: failing to meet the requirements of the PBR; misrepresenting or failing to disclose fully all relevant facts in obtaining the permit; or being indebted to the state for fees, payment of penalties, or taxes imposed by the statutes or rules within the commission's jurisdiction. Furthermore, a denial under this section constitutes a final commission action.

Pioneer commented that the phrase, "For good cause" is far too vague and allows too much latitude for the commission. If a facility meets the conditions of the PBS, it should be approved. Furthermore, it is not legal to deny coverage under a "good cause" clause for a reason not stated in the conditions for qualifying for coverage.

ETC commented on subsection (c)(3) and stated that, "The PBR sets forth a sweeping and potentially important provision: "The commission may deny an application under this section for good cause." ETC asserts that this language is arbitrary and should be deleted from the proposed rule. The regulated community is entitled to notice as to the activities and requirements that will, and will not, allow parties to claim the PBR. No adequate guidance or notice is provided through the general and entirely vague notion of denial for "good cause." If parties meet the specific requirements of the PBR as it is finally promulgated, then they are entitled to apply for registration. The commission should not, and may not, retain a vague and unspecified power to deny, for some sort of "good cause," a registration that meets the specific and detailed requirements that are contained in the rule."

TPA also commented that in subsection (c)(3), "Good cause" is not a legitimate basis for denial of an application. In subsection (c)(3) of the proposed PBR and subsection (c)(4) of the proposed Standard Permit, it is provided that the commission may deny an application for "good cause." TPA submits that this provision be deleted or amended. The regulated community is entitled to notice as to the activities and requirements that will, and will not, allow parties to be registered under the PBR or Standard Permit. No adequate guidance or notice is provided through the general and entirely vague notion of denial for "good cause." If parties meet the specific requirements of the PBR or Standard Permit as each is finally promulgated, then they are entitled to apply for registration. The commission should not, and may not, retain a vague and unspecified power to deny, for some sort of "good cause," a registration that meets the specific and detailed requirements that are contained in the rule.

TXOGA commented that, "Good cause" is far too vague and allows too much latitude for the commission. If a facility meets the conditions of the PBR it should be approved. Furthermore, it is not legal to deny coverage under a "good cause" clause for a reason not stated in the conditions for qualifying for coverage.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA stated that denial for good cause is arbitrary and that arbitrary in proposed§106.352(c)(3) and Standard Permit proposed standard permit subsection (c)(4) would allow TCEQ's commission to deny the proposed PBR or proposed standard permit registration for "good cause." If a regulated entity has met the requirements of the proposed PBR or the proposed standard permit, as finally adopted, the TCEQ is prohibited constitutionally from denying the authorization, as explained in more detail below. "{A} statute that forbids the doing of an act in terms so vague that persons of common intelligence must necessarily guess at its meaning and differ as to its application violates an essential element of due process." In other words, law is "void for vagueness . . . if it is inherently standardless, enforceable only on the exercise of an unlimited, and hence arbitrary, discretion vested in the state."It is well-settled that statutes and ordinances that lack any criteria, essentially vesting the government with unfettered discretion to deny permits are unconstitutionally vague.

This subsection has been revised to provide the specific circumstances for which the commission may deny a PBR. The revised language states that the reasons the commission may deny a PBR include: failing to meet the requirements of the PBR; misrepresenting or failing to disclose fully all relevant facts in obtaining the permit; or being indebted to the state for fees, payment of penalties, or taxes imposed by the statutes or rules within the commission's jurisdiction. Furthermore, a denial under this section constitutes a final commission action.

The Sierra Club commented that, "It is not clear whether the proposal covers fugitive emissions from the fracturing process. Since air emissions from hydraulic fracturing pose serious health concerns, we request TCEQ to clarify whether it is regulating air emissions from the fracturing process."

One individual requested "the TCEQ to clarify whether it is regulating air emissions from the fracturing process."

The proposed PBR and standard permit do not regulate air emissions from hydraulic fracturing activities. Hydraulic fracturing consists of pumping large volumes of chemically treated fresh water and sand into shale formations. The injection of the pressurized water creates fractures in the shale, which are then held open by the sand. The fractures increase the surface area from which the gas can be retrieved and increase the ease of moving the gas. Hydraulic fracturing presents technical issues and policy concerns that are not found in other oil and gas activities. Therefore, it is not appropriate for the commission to regulate hydraulic fracturing under the proposed PBR and standard permit. However, once the hydraulic fracturing process is complete at a particular site, the PBR and standard permit do regulate the air emissions from subsequent oil and gas activities at those same sites.

One individual stated that, "In terms of quality, the Clean Water Act was made into law before the fracking process was developed. The Old Town Neighborhood Association commented that, "The risk of ground water contamination has grown exponentially in recent years due to over 265 percent growth in natural gas drilling. When combining that risk with the relatively new horizontal fracturing technology, that further increases the risk because horizontal fracturing can reach more subsurface footprint by around 6,400 percent than the traditional vertical drilling. All hydraulic fracturing should be permitted only with ground water monitoring wells nearby that test the water during the life of the well."

One individual recommended that, "Companies should be required to submit baseline tests before any exploration takes place. Our County Groundwater District does not have the authority to monitor the drilling of water well nor the amount of water being used by the Oil and Gas Industry. As landowners, we do not know what chemicals are being injected into our groundwater either. We also do not have any idea what particles are in our air due to a nearby Coal Plant and the Oil and Gas production in our area. I welcome more information and action on the part of TCEQ to regulate these industries."

One individual stated that, "Companies should be required to submit baseline tests before any exploration takes place. Our County Groundwater District does not have the authority to monitor the drilling of water well nor the amount of water being used by the Oil and Gas Industry. As landowners, we do not know what chemicals are being injected into our groundwater either. We also do not have any idea what particles are in our air due to a nearby Coal Plant and the Oil and Gas production in our area. I welcome more information and action on the part of TCEQ to regulate these industries."

The commission has not changed the rule in response to this comment. The proposed PBR and standard permit are air quality authorizations and therefore, water quality issues are outside the scope of this rule package. Should the nature of and oil and gas facility's operations require, the owner or operator may need to obtain separate permits to regulate water quality.

TPA requested clarification and commented on "Subsection (d)(1) - Clarification is needed as to possible coverage in the PBR and standard permit of non-emergency combustion units. Subsection (d)(1) sets forth the kinds of facilities that may be included in a registration under PBR and standard permit. Subsection (d)(1)(H) lists "combustion units, including engines, turbines, boilers, reboilers, heaters and heater-treaters." It is unclear whether TCEQ intends to include only non-emergency combustion units in this listing. In addition, the inclusion of such language in the proposed PBR leaves unclear the question of whether emergency units may still claim the PBR §106.511. TPA urges the TCEQ to provide additional clarity on these issues."

The commission does not intend any units that are not engines or turbines to be called emergency and not subject to the proposed rule. The commission only intends emergency engines and turbine to continue to be authorized under PBR §106.511.

EPA stated that §116.620(d)(1)(D) allows changes made under standard permit to be authorized using PBR §106.261 and §106.262. EPA also stated that "§116.620(d)(2)(D) and §106.352(d)(1)(E) excludes Liquefied Petroleum Gases (LPG), crude oil, or condensate transfer or loading into or from railcars, ships, or barges, but allows them to be authorized under PBR §106.261 and §106.262. Concerns have been raised to EPA that some PBRs (106.261 and §106.262) may not meet the requirements of the federally approved Texas SIP. These concerns have been raised in two citizen petitions filed with the EPA, dated August 28, 2008, and January 5, 2009. EPA will be evaluating the construction and use of these PBRs at a future date."

The commission appreciates the concerns and will work with the EPA in addressing concerns with other PBRs.

TPA commented on subsection (d)(2)(H). "Legal effect should not be given to the APWL. Subsection (d)(2)(H) of the proposed PBR and standard permit provides that one of the items not authorized under the PBR and standard permit is "any emission increase in an Air Pollutant Watch List area for one or more applicable Air Pollutant Watch List contaminants designated for that area." Such a provision would mean that there would be binding legal consequences based on whether or not a contaminant was on the Air Pollutant Watch List ("APWL"). It would be inappropriate to make coverage of the PBR or standard permit hinge on whether or not a contaminant was on the APWL. The APWL is not a formal standard promulgated by the Legislature in a statute or by the Commission in a rulemaking proceeding; rather, it is promulgated by the Toxicology Division in order to heighten public awareness and encourage efforts to reduce emissions. As such, the APWL is not the product of the sort of rigorous scrutiny associated with the legislative or regulatory rulemaking process. The Toxicology Division's decision as to what contaminants should be on the APWL should not serve as the deciding factor as to whether an emission increase is covered by the PBR or standard permit. Moreover, the TCEQ is once again singling out the oil and gas industry. No other industry is subject to this same limitation in terms of threshold applicability of a PBR or standard permit. If the chemical industry, manufacturing industry, or any other industry sought to use a PBR or standard permit to authorize an air contaminant in an area where that pollutant is on the APWL, then it would not be prohibited from doing so. If the TCEQ wishes to implement this standard, it should subject the APWL to a formal rulemaking, then proceed to limit the use of all PBR and standard permit authorizations from authorizing pollutants on the APWL by use of those permit mechanisms. It is simply unfair and unjustified to single out the oil and gas industry, once again, by establishing this as a threshold standard."

The commission has changed the rule in response to this comment. Although this evaluation will not be specifically required by rule, the commission will continue its policy and practice to evaluate any and all projects located in APWL areas. The use of the APWL is appropriate and necessary to protect areas within the state that have detected elevated levels of certain specific contaminants. The commission reviews ambient air monitoring data from mobile monitoring and fixed-site monitoring networks to assess the potential of monitored concentrations to cause adverse health effects. Specific chemicals in locations that are a concern for adverse health effects and odor conditions are place in the APWL. The commission's continuing focus and evaluation of projects under PBRs in the APWL areas will help the commission attain its goal of improving air quality in these areas and is necessary due to existing monitoring problems in areas of the state where these, or any other similar sources, should not additionally contribute to air quality problems.

EDF specifically supports the prohibition pertaining to emissions increases in APWL areas for applicable contaminants. This provision will help the state to more effectively manage air quality in these impaired areas.

The commission has deleted subsection (d)(2)(H). Although this evaluation will

not be specifically required by rule, the commission will continue its policy and practice to evaluate any and all projects located in APWL areas. The use of the APWL is appropriate and necessary to protect areas within the state that have detected elevated levels of certain specific contaminants.

Exterran commented that, "The Texas Clean Air Act modification exemption for maintenance and replacement components should apply to the engine replacement and will not impede progression of better performing engines and lower engine standards on existing SI RICE. (Section D). The Texas Clean Air Act ("TCAA") allows TCEQ to adopt PBR to authorize a "new facility" or to "modify an existing facility" that "will not significantly contribute air contaminants to the atmosphere"(THSC, §382.051 and §382.05196). Further, the TCAA specifically exempts from the definition of "modification of existing facility" any "maintenance or replacement of equipment components that do not increase or tend to increase" or change emissions (THSC, §382.003(9)). The engine is just one component of the facility that drives the compression of natural gas. The compression facility consists of integral engine components such as the engine, engine cooler, engine exhaust, and wiring. As with any facility, equipment must undergo routine maintenance and repair to ensure optimal operation, in which this case would involve removing the core engine portion of the facility and replacing that engine with a similar make/model to minimize downtime as well as provide a higher level of maintenance for the overall facility. Consistent with these TCAA provisions, the routine replacement of just the engine portion of the facility (and not the associated cooler, exhaust or wiring portions) does not "significantly contribute to air contaminants" and should not be considered a "modification to an existing facility" or a "new facility" that requires reauthorization under a new PBR due to the replacement alone. Recommendation: Clarify that the proposed PBR and standard permit apply the TCAA replacement exemption from modification to engine-only maintenance replacements that do not increase or change the character emissions. Specifically, the respective proposals should be amended to read as follows: The proposed PBR should be amended by deleting proposed PBR §106.352(e)(4)(A) and moving it to a new proposed PBR §106.352 (f)(7) to read as follows, " Engines (excluding replacement engines that do not increase the previously registered emissions or potential to emit emissions) and turbines shall meet the emission and performance standards listed in Table 9 in subsection (m) of this section.""

The commission did not change the rules in response to this comment. A replacement engine is a new facility and must meet the requirements of the PBR rule, unless otherwise specified. As stated in 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. A new engine must meet applicable federal requirements. Further information can be found in the section by section discussion for subsection (b).

Exterran commented that, "When the engine is the only component of the facility replaced during maintenance, requiring a new authorization for the replacement of an engine seems to discourage the very replacement, repair and maintenance encouraged by the TCAA modification exclusion. Additionally, state and federal engine standards which impose additional criteria and HAPs emission reductions on virtually all SI RICE should also be considered. Imposing "new authorization" requirements upon replacement engines already subject to aggressive state or federal law will create duplicative and conflicting requirements. Recommendation: Clarify that the proposed PBR and standard permit apply the TCAA replacement exemption from modification to engine-only maintenance replacements that do not increase or change the character emissions. Specifically, the respective proposals should be amended to read as follows: The proposed PBR should be amended by deleting proposed PBR §106.352(e)(4)(A) and moving it to a new proposed PBR §106.352 (f)(7) to read as follows, " Engines (excluding replacement engines that do not increase the previously registered emissions or potential to emit emissions) and turbines shall meet the emission and performance standards listed in Table 9 in subsection (m) of this section.""

The commission did not change the rules in response to these comments. A replacement engine is a new facility and must meet the requirements of the PBR rule, unless otherwise specified. As stated in 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. A new engine must meet applicable federal requirements. The commission deleted engine testing requirements for VOC and formaldehyde in response to other comments. Further information can be found in the section by section discussion for subsection (b).

Exterran noted that "in addition to the Texas Clean Air Act general permitting requirements, recent state and federal regulatory requirements for SI RICE continue to promote aggressive emission standards on engines regardless of authorization. In other words, on top of the routine replacements which maintain or improve engine performance under the existing Standard

Permit and PBR authorizations, SI RICE are now also subject to a more stringent state and federal emission standards and operation requirements. The following state, federal 40 CFR Part 60 NSPS and 40 CFR Part 61 NESHAP regulations have created lower, more stringent emission standards or management practices on SI RICE: Chapter 117 of the Texas Administrative Code imposes lower NO_X standards on certain SI RICE engines. 40 CFR Part 60 NSPS imposes lower NO_X and VOC emission standards on new or reconstructed engines. 40 CFR Part 60, Subpart JJJJ. 40 CFR 61 NESHAP has recently imposed hazardous air pollutant emission standards which will require catalytic control requirements on virtually all new and existing SI RICE greater than 500 hp and management practices for many engines less than 500 hp. 40 CFR Part 63, Subpart ZZZZ. Instead of imposing potentially duplicative and costly emission standards on existing SI RICE, replacement SI RICE should be subject to the applicable state and federal requirements already in place to impose emission reductions on existing engines. Reliance on existing state authorizations, in addition to Texas and federal engines standards, avoids disproportionately impacting replacement engines in Texas when compared to other states which must only comply with federal standards."

Targa "routinely moves existing engines to different compressor station locations to accommodate the ever-changing natural gas throughput needed as flow rates change drastically depending on where new wells are coming online throughout our gathering systems. Targa believes §106.352 should reference §106.512 only and incorporate by reference 40 CFR Part 60, Subparts JJJJ and IIII, as well as and 40 CFR Part 63, Subpart ZZZZ. These Federal regulations are more stringent than current §106.512 and are already determined to be protective of air quality by the EPA."

The commission has changed in the rule in response to this comment. The proposed PBR rule allows anything done to comply with other federal or states rule to also be used for state purposes and minimize any additional cost to industry. After a detailed review of submitted information and federal background documents for 40 CFR 63 NESHAP Subpart ZZZZ, the commission has determined that the requirements of this federal standard is sufficient to establish controls on formaldehyde on new and existing engines. This is further supported by recent monitoring and does not show any concerns with monitored values of formaldehyde from engines associated with oil and gas production sites. Therefore, formaldehyde is omitted from the impacts evaluation requirements and emission limits for this PBR.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that the text of the rule should use the phrase PBR, not standard permit.

The commission agrees with this comment and has made this change.

Phased Implementation

Representative Lon Burnam stated his support for the state-wide scope of the proposed rules because drilling intensity shifts regionally and emphasized state-wide application gives regulatory consistency.

The commission appreciates the support and agrees that state-wide applicability ensures protection of all citizens of the state and establishes regulatory consistency for industry.

EDF stated "The TCEQ should phase in a requirement that existing facilities statewide, or at least in the East Texas Region, must obtain a new OGS authorization within 3 years of rule adoption, or 18 months in nonattainment areas or affected counties. Such a requirement would ensure that emissions from thousands of individual OGS sites in the Region are protective of public health. For the rest of the state, the TCEQ should require any facility filing only for an MSS permit under §106.352(b)(7) to provide certified estimates of emissions from their site demonstrating current compliance with their previous claim of authorization under this section."

The commission has not changed the rule in response to these comments and is requiring the applicability of all new projects throughout the state to comply with the new requirements as of the applicability date of April 1, 2011 or January 5, 2012, depending on location. The commission has not changed subsection (b)(7) and existing authorized facilities, or group of facilities, at an OGS must only meet subsection (i) no later than January 5, 2012.

ETC recommended "A period for transition to the new PBR requirements should be included. The re-authorization requirements that will be imposed upon facilities that are new or that are increasing emissions should not be instantly imposed. If a triggering event (e.g., a site change that increases emissions) resulted in immediate application of the re-authorization requirements under the proposed PBR, this might create a situation where the facility would instantly fall into non-compliance. A facility may need time in order to alter certain site components so as to comply with the re-authorization requirements. Accordingly, the rule should be revised to include a period of 6 months for complying with any re-authorization requirements, so that facilities have sufficient time to achieve compliance with the new regulatory requirements."

After further analysis of comments, the commission has created a combined notification and registration system. Information on new projects will be required prior to construction, and information would be electronically submitted and available on-line almost immediately. Within 90 to 180 days (depending on scope of project) registered or certified information will be submitted for equipment, materials, and operations. This delay will provide an opportunity for confirmation of such details which are essential to accurately estimate emissions, and longer periods of time are only allowed for the smaller groups of facilities. In addition, the commission has established a phased implementation schedule for the new PBR and standard permit, depending on location in the state. For projects in the Barnett Shale area, the new requirements are effective April 1, 2011. For all other projects in the state, the effective date is January 5, 2012.

TAEP opposed the requirements and stated "Short of terminating this rulemaking, the Alliance would urge that you slow the rate of the rulemaking and its statewide implementation. We would urge you to integrate the necessary MSS into the current PBR."

The commission partially agrees with the commenter and is delaying the effective date of the PBR to April 1, 2011 for projects in the most active shale area. All other projects statewide will not use the new PBR until January 5, 2012. The commission respectfully disagrees with otherwise delaying this rulemaking and only update the previous version of §106.352 for planned MSS. Once any rule is opened for substantive technical requirements, it has been the consistent practice of the commission to ensure that all related technical requirements are based on current science and knowledge. The previous PBR had not been updated in over 20 years and there has been substantial changes in accurately characterizing and quantifying emissions, available recovery techniques, and ensuring protection of public health and welfare based on current ESLs and ambient air quality standards.

The PBPA also was concerned and stated "It is extremely imprudent to hit the industry with this much new regulation this fast. There is no gradual lead-up to the massive and expensive new requirements and associated, imposed new costs."

The commission respectfully disagrees with the commenter that the revised requirements and changes to the PBR and standard permit are being adopted too rapidly. The commission has been working informally with industry throughout the state since 2004 on updates and possible requirements, including several local

and Austin stakeholders meetings. As discussed above, the commission has also carefully scrutinized all new costs associated with the revised requirements and minimized costs and expectations where appropriate. The preconstruction registration requirements have been replaced with notification and 90 to 180-day follow up registration submittal through the ePermits system with an immediate response. This process is intended to provide information to the public and commission, as well as ensure no economic delays.

Encana stated "TCEQ could make greater differentiation between sources in attainment versus nonattainment areas allowing more flexibility in attainment areas. The proposed PBR requirements do not differentiate between facilities located in attainment versus non-attainment areas. Encana would like the TCEQ to consider modifying the PBR requirements to take into account attainment areas and nonattainment areas, many of the-monitoring requirements proposed in the PBR such as the site LDAR program are similar to programs put in place in nonattainment areas in other states. Because of the variation in location of OGS across the state of Texas, Encana believes it is appropriate to make distinctions in monitoring requirements for attainment and non-attainment areas."

The commission has not changed the rule in response to this comment. The requirements of best management practices, emissions limits, protectiveness, monitoring, sampling, and recordkeeping are appropriate for any new project constructed at any location in the state. Consistent with the Texas Clean Air Act (THSC, Chapter 382), the PBR is adopted with requirements to ensure

insignificance, practical enforceability, and protection of the general public at any location in Texas.

Encana additionally commented that the PBR should take into account the different conditions in regions across the state. Other states have established a precedent for this approach. States such as Colorado and Wyoming have tailored their rules for air pollution controls of OGS based upon various geographical and operating conditions for the respective areas in each state. The TCEQ should consider the development of a "basin-wide" segmented approach to be applied to different conditions and regions in the state. This approach would help address Encana's concerns stated above regarding different requirements for attainment and nonattainment areas.

The commission has not changed the rule in response to this comment. Other states laws and rules are based on individual state's statutes which are not the same as those in Texas. Additional restrictions on projects and facilities in nonattainment areas are stipulated in 30 TAC Chapters 115 and 117 and are more stringent than those in the revised PBR. A distinction based on shale area has been used for applicability purposes in the adopted rule.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented that the statute requires TCEQ to recognize circumstances in which there may be a need to control air emissions in one area of the state but not another. TCEQ is required to consider "the fact that a rule and the degrees of conformance with the rule that may be proper for an essentially residential area of the state may not be proper for a highly developed industrial area or a relatively unpopulated area."Thus, the Legislature expressly directs TCEQ to adopt air quality rules that are tailored to address specific issues in specific areas or geographic regions, rather than adopting statewide rules, if statewide rules are not warranted.

The commission has not changed the rule in response to this comment. The commission agrees that there should be greater emissions restrictions on facilities which are in close proximity to the general public, and has included very specific requirements to confirm protectiveness for any oil and gas registration. Other areas in the state with air quality problems are designated as nonattainment and have additional restrictions as adopted in Chapters 115 and 117 to address those issues, and those requirements are more stringent than the adopted PBR, as consistent with the statute.

TAEP recommended that the new PBR and standard permit should be implemented first in those areas of the state that currently have health or safety issues, (nonattainment or near nonattainment areas) and those areas with the greatest population." They also stated that the rule should be focused on those areas of Texas that have current air quality or health and safety issues. TCEQ should concentrate in the areas of the state that are currently in nonattainment or near nonattainment. TCEQ should focus on geographic areas where there is a high activity level of drilling and production. TCEQ should then focus on high volume production with high potential to emit. TAEP would believe that the new rule should be limited to the Barnett Shale until such time that the results of the Barnett Shale Special Inventory have been completed, and reviewed, and that TCEQ establish that natural gas drilling and production is a major contributor to health and safety risks for the citizens of the area.

TIPRO commented that rules should be targeted toward areas of high population or high density of wells. TIPRO does not want to cause asthma in children, and it wants to help citizens stay happy and healthy. This can be done in a cooperative manner and asks that the TCEQ consider a regional, rather than a statewide application of the new rule package for PBR, regardless of what it looks like at time of adoption. Efforts to address air quality issues should focus on areas in which air quality has been officially established as problematic by EPA standards. Oil and gas operators in largely rural, remote areas should not have to abide by the same standard as those who operate in close proximity to urban areas.

The commission partially agrees with the commenter and is making the effective date of the PBR to April 1, 2011 for projects in the most active shale area. All other projects state-wide will not use the new PBR until January 5, 2012. The commission has established the PBR to be consistent with the Texas Clean Air Act (THSC, Chapter 382), the PBR is adopted with requirements to ensure insignificance, practical enforceability, and protection of the general public at any location in Texas. Consistent with the TCAA, the PBR is adopted with requirements to ensure insignificance, practical enforceability, and protection of the general public at any location in Texas. Regardless of urban or rural location, any member of the general public in close proximity of a new or changing oil and gas facility should expect equal protection of their health and welfare. Areas

which are designated as nonattainment have additional restrictions as adopted in Chapters 115 and 117 to address those areas' air quality issues, and those requirements are more stringent than the adopted PBR. Instead, the commission is making the effective date of the PBR April 1, 2011 for projects in the most active shale area currently in the state. All other projects statewide will use the new PBR after January 5, 2012.

TAEP also recommended that the commission "Defer implementation of further changes until the results of the Barnett Shale Special Inventory on emissions are complete and understood. Make only the Barnett Shale area subject to the new rule before you begin a comprehensive program throughout the state."

The commission has not changed the rule in response to this comment. The Barnett Shale Special Inventory is intended to better characterize and indentify cumulative emissions in a densely populated urban area, of which many counties are also not attaining national air quality standards. The outcome of this Inventory will be used to address specific concerns for that area and not to establish requirements for any OGS in Texas. The commission is making the effective date of the PBR April 1, 2011 for projects in the Barnett shale area in the state. All other projects statewide will use the new PBR after January 5, 2012.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented "Geographic Limitations of the proposed PBR and proposed standard permit would be a more reasonable approach If TCEQ ultimately decides to move forward with a new PBR and standard permit for OGS, TXOGA believes that it would be appropriate for TCEQ to limit the scope of the proposed PBR and proposed standard permit (as modified based on the technical comments attached as Exhibit 3) to metropolitan statistical areas, and after implementation, consider whether to phase-in the requirements in other parts of the state. TCEQ states in the preamble to the proposed rules that the proposed changes "are particularly critical for OGS in urban locations or in close proximity to the public." This situation is much different than the typical situation of OGS located far away from residences or other receptors. As a result, TXOGA believes that if the proposed PBR and proposed standard permit are adopted, they should be made applicable only in metropolitan statistical areas."

The commission partially agrees with the comment and has changed the rule in response. The commission respectfully declines to establish effective dates of the new requirements of the PBR first on "metropolitan statistical areas", and at a later date for other areas of the state. Regardless of urban or rural location, any member of the general public in close proximity of a new or changing oil and gas facility should expect equal protection of their health and welfare. Instead, the commission is making the effective date of the PBR April 1, 2011 for projects in the most active shale area currently in the state. All other projects statewide will use the new PBR after January 5, 2012.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented, "The primary motivating factor behind the proposed PBR and proposed standard permit is to address concerns raised by the public in urban areas in the Barnett Shale area."

The commission respectfully disagrees with the commenter that the revised requirements and changes to the PBR and standard permit are primarily in response to the concerns in the Barnett Shale area. The commission has been working informally with industry throughout the state since 2004 on updates and possible requirements, well before frequently drilling began in the Barnett Shale area.

TPA stated the "TCEQ should implement these new authorizations in the Barnett Shale area only. There is precedent in other states for the use of regional or basin-wide rules. We understand from TCEQ Staff that rules adopted in Wyoming and Colorado served as the model for many of the provisions in the proposed PBR, yet both Wyoming and Colorado have rejected the "one size fits all" approach. Wyoming's rules establish different requirements (e.g., for flash emissions, blowdown/venting, produced water tanks, well completions, dehydrator controls, and pneumatic pumps) depending on whether the source is in a Concentrated Development Area, the Jonah and Pinedale Anticline Development Area ("JPAD"), or the remainder of the state. (See Oil and Gas Production Facilities: Chapter 6, Section 2 Permitting Guidance, available at *http://deq.state.wy.us/aqd/oilgas.asp* (open "3/10 Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance") (2010)). Indeed, in reaction to increased production activity such as that now being experienced in the Barnett Shale, the Wyoming Department of Environmental Quality in 2004 established emission control strategies tailored to the JPAD Area, one of the richest concentrations of natural gas in the nation, by revising emission control requirements under the Presumptive BACT permitting process in order to address intensified production activity and increased concentration of gas/condensate production equipment in the JPAD area. (See Jonah and Pinedale Anticline Gas Fields: Additions to Oil and Gas Production Facility Emission Control and Permitting Requirements, available at *http://deq.state.wy.us/aqd/oilgas.asp* (open "7/28/04 Additional Guidance - Jonah & Pinedale Anticline Gas Fields")(2004)). The agency did not, however, see fit to make those control requirements applicable to the entire state of Wyoming."

The commission has not changed the rule in response to this comment. Staff has reviewed Wyoming and Colorado regulations as a part of the background evaluation for the proposal. It is important to note that both states have very distinctive areas of oil and gas exploration and production, concentrated in the Basins and areas identified above. In both states there is little additional oil and gas activity in the remaining portions of the state. Additionally, Colorado's rules require each piece of equipment (facility) to meet prescribed control requirements and obtain individual authorizations. Wyoming's rules also depend on "presumptive" BACT controls to authorize facilities by a streamlined mechanism. Neither of these approaches is recommended for Texas' PBR, instead controls are optional and choices that operators may make to reduce or eliminate emissions are optional, but best management practices are minimum requirements.

TAEP stated that, "The new PBR and standard permit should be implemented first in those areas of the state that currently have health or safety issues, (nonattainment or near nonattainment areas) and those areas with the greatest population."

TIPRO also stated that, "Rules should be targeted toward areas of high population or high density of wells. We do not want to cause asthma in children, and we want to help citizens stay happy and healthy. This can be done in a cooperative manner."

The commission partially agrees with the comment and has changed the rule in response. The requirements of best management practices, emissions limits, protectiveness, monitoring, sampling, and recordkeeping are appropriate for any new project constructed at any location in the state. The commission is making the effective date of the PBR April 1, 2011 for projects in the most active shale area currently in the state. All other projects statewide will use the new PBR after January 5, 2012.

The PBPA stated "It is extremely imprudent to hit the industry with this much new regulation this fast. There is no gradual lead-up to the massive and expensive new requirements and associated, imposed new costs."

The commission respectfully disagrees with the commenter that the revised requirements and changes to the PBR and standard permit are being adopted too rapidly. The commission has been working informally with industry throughout the state since 2004 on updates and possible requirements, including several local

and Austin stakeholders meetings. As discussed above, the commission has also carefully scrutinized all new costs associated with the revised requirements and minimized costs and expectations where appropriate.

Kinder Morgan stated "Regional issues related to the Barnett Shale do not justify state-wide applicability for the PBR. There has been much public concern expressed over the potential or perceived impact of natural gas production, gathering, and transmission activities in the Barnett Shale area, particularly in and around the urban areas. While there have been publicly funded health studies and numerous ambient air quality studies performed by private consultants, the TCEQ, and other publicly funded organizations, none of these studies have indicated chronic, long-term, adverse health effects due to these activities. Accordingly, with no demonstrated harm from these activities, the TCEQ may not have a rational basis to implement the revisions to the OGS PBR and standard permit in the Barnett Shale area and certainly is not justified in requiring the full implementation of these revisions across the state."

TIPRO "asks that the TCEQ consider a regional, rather than a statewide application of the new rule package for permit by rule, regardless of what it looks like at time of adoption. Efforts to address air quality issues should focus on areas in which air quality has been officially established as problematic by EPA standards. Oil and gas operators in largely rural, remote areas should not have to abide by the same standard as those who operate in close proximity to urban areas."

TPA stated "TCEQ's proposed OGS PBR could be similarly tailored to apply to facilities located in a geographically defined area of the state, such as the Barnett Shale or nonattainment areas, and within a certain distance of a receptor. TCEQ's protectiveness standards are risk based, that is, exposure pathways to affected populations are taken into account when setting standards or driving controls. Accordingly, the standard that should apply in highly populated areas should not be the same standard that should apply in rural areas. There is simply no rational basis to apply the new rules state-wide. The costs to comply with the proposed OGS PBR and standard permit as proposed will be very high. Particularly in the rural areas, the cost per ton reduction will be very high with little attendant improvement in air quality. More analysis needs to be performed to justify imposition of this very complex and costly new authorization on a state-wide basis."

TAEP commented that, "The rule should be focused on those areas of Texas that have current air quality or health and safety issues. TCEQ should concentrate in the areas of the state that are currently in nonattainment or near nonattainment. We should focus on geographic areas where there is a high activity level of drilling and production. We should then focus on high volume production with high potential to emit. We would believe that the new rule should be limited to the Barnett Shale until such time that the results of the Barnett Shale Special Inventory have been completed, and reviewed, and that TCEQ has established that natural gas drilling and production is a major contributor to health and safety risks for the citizens of the area."

TXOGA, Anadarko, Noble, ExxonMobil, and GPA stated "Geographic limitations of the proposed PBR and proposed standard permit would be a more reasonable approach If TCEQ ultimately decides to move forward with a new PBR and standard permit for OGS, TXOGA believes that it would be appropriate for TCEQ to limit the scope of the proposed PBR and proposed standard permit (as modified based on the technical comments attached as Exhibit 3) to metropolitan statistical areas, and after implementation, consider whether to phase-in the requirements in other parts of the state." They also stated "The primary motivating factor behind the proposed PBR and proposed standard permit is to address concerns raised by the public in urban areas in the Barnett Shale area." "TCEQ states in the preamble to the proposed rules that the proposed changes "are particularly critical for OGS in urban locations or in close proximity to the public." This situation is much different than the typical situation of OGS located far away from residences or other receptors. As a result, TXOGA believes that if the proposed PBR and proposed standard permit are adopted, they should be made applicable only in metropolitan statistical areas."

Markwest commented "As it is currently drafted, the proposed PBR revisions will apply state-wide, even though the proposed changes appear to be driven by the development of the Barnett Shale. MarkWest does not have operations in the Barnett Shale. It is not appropriate for state-wide operators to face new requirements that will cost significant sums of money and slow the development of the State's natural resources to address the concerns that stem from only the Barnett Shale. Further, despite numerous studies that fail to demonstrate any significant emissions or environmental issues directly relating to the increase in production in the Barnett Shale, the proposal places significant new regulatory burdens and hurdles on operators. If any changes are warranted, they should be tailored to the issue or concerns at hand, in this case, a specific regional area."

In 2007 the commission conducted a special monitoring project in its Houston region. The region monitored 30 sites, 17 of which (57 percent) had VOC emissions visible with an infrared camera. Leaking components included hatch seals, pressure relief valves, water tanks, and glycol still vents. Downwind samples consistently documented concentrations of hazardous air pollutants such as benzene and toluene. Most emissions observed during the project resulted from a lack of routine maintenance on hatch seals and separator valves. The current oil and gas PBR includes no requirements for routine maintenance of equipment. The new PBR and standard permit include best management practices which require closed hatches and seal of all units to be kept in good working order.

The growing use of the FLIR GasFindIR camera has allowed the commission's technical staff to characterize and assess emissions from OGS more accurately. Since 2006, the mobile response team (MRT) has conducted more than 25 monitoring trips to study these emission sources across the state of Texas including trips to Corpus Christi, Point Comfort, Ingleside, Houston, Pearland, Freeport, Texas City, Mont Belvieu, Beaumont, Port Arthur, Midland, Odessa, Longview, Mexia, Franklin, and Fort Worth. Further work by regional staff has established that natural gas and oil emissions are not confined to these areas, as they have been visualized, measured, and/or investigated in all geographic locations of Texas. The commission is still in the process of characterizing these emissions, but the use of the GasFindIR camera in other commission applications has led to the understanding that emissions have been historically underreported.

This underreporting was evident in the 2005 Upstream Oil and Gas Project when the commission provided technical guidance to a project that directly measured speciated VOC emissions from oil and condensate storage tanks at wellhead and gathering site tank batteries along the Texas Gulf Coast. New emission factors were established and the commission added approximately 700,000 tpy of statewide emissions. Additionally, the infrared camera detected many previously unidentified emissions along the Houston Ship Channel. Although the design of some of these storage tanks differ from the fixed-roof product and condensate tanks that exist at upstream oil and natural gas sources, all storage tanks are designed to equalize pressure to prevent both explosion and implosion incidents. As a result, storage tanks of any type would be expected to release VOC emissions unless a vapor recovery system is installed to minimize emissions.

Follow-up investigations have indicated that many of these source types have underrepresented emissions. The new PBR and standard permit help resolve some of these underreporting issues by relying on site-specific or representative gas and liquid analyses, updated calculation methods, best management practices, and an evaluation of off-site impacts to show protection of public health and welfare for all new or modified sites.

One specific case of underrepresented oil and natural gas emissions was first identified through a commission's air-shed monitor that was located adjacent to a residential area. Commission investigators presented IR images to an energy company which showed excessive VOC emissions from storage tanks. The

company hired an external contractor who measured and calculated these emissions for consistency with the company's claim of PBR status. After completing testing, these VOC emissions were actually estimated in excess of 370 tpy, more than 14 times the PBR limit of 25 tpy. Though this is but one example of underreported emissions; commission investigative efforts tend to indicate that emissions of this magnitude are not confined to one company or geographic location but are occurring throughout Texas. A similar survey of 22 tank batteries in the Midland region revealed five tank batteries that were venting over 100 tpy. All of these venting tanks were found as a result of complaints.

Commission monitoring and field assessments cover multiple natural gas and oil emission sources involved in the production and processing of oil and gas. These sources include: drilling, fracturing, well-heads, condensate and product storage tank batteries, compressor stations, saltwater disposal wells, and natural gas processing facilities. These sources are permitted by the commission to release air emissions. However, several years of field work have demonstrated that a notable portion of fugitive emissions also come from other sources that are not regulated under the current PBR and standard permit. These sources include open tank hatches, tank seal issues, tank integrity problems, pressure relief valves, vent stacks, unlit flares, truck loading and unloading activities, vent gaskets, leaking vent flare arrestor caps, dirty flare arrestor caps, heater treater pressure relief valves, vessel fittings, controller boxes, vent control valves, gun barrel separators, glycol dehydrators, and blow down valves.

Based on this information and information used to develop the rule proposal, the commission concludes that the current §106.352 is not adequate to ensure public health and safety and does not meet the intent of the TCAA. However, the commission recognizes the dramatic changes this rule will have on the industry, the agency, and the public. The commission, like all state agencies, is faced with helping resolve substantial budget deficits and has limited resources. To ensure that the commission is making the revised requirements for new projects applicable after various dates to ensure that there is sufficient time after adoption for regulated entities to plan accordingly as well as ensure that the commission has ePermits, emission calculation guidance, tools available to customers, as well as completing outreach. To ensure an accurate and comprehensive authorization system, agency resources must be focused on all oil and gas registrations, and the highest volume are for facilities located in the growing shale areas. Therefore, the commission has included an applicability date of April 1, 2011 for the Barnett Shale area. This area has been chosen due to the high volume of current and anticipated drilling. The remaining portions of the state would be applicable for new projects as of January 5, 2012.

Devon "wishes to ensure that the proposed PBR and standard permit requirements are practical, achievable, and appropriate. The timeline for implementation of these proposals is short and does not account for the various Texas air emission studies that have been conducted. There have recently been several studies in the densest drilling and production areas of the Barnett Shale which have shown no air quality concerns attributed to oil and gas sites. Specific examples of recent studies include: A Rice University study in August 2009 concluded that VOC levels in the DFW area are comparable to those found in other urban areas, VOC levels detected were below adverse health or welfare effects levels, and cars and non-OGS industrial activities are the primary source of benzene in the DFW area; In January 2010, the TCEQ announced the results of 2009 air sampling exercises around OGS, concluding that no pollutants were found at levels that would cause concern and that VOCs were not detected at most of the OGS tested; A May 2010 study by the Texas Department of State Health Services (TDSHS) collected biological samples from Dish, Texas residents to evaluate their exposure to VOCs from OGS and concluded that there was no pattern of elevated, community-wide exposure to VOC; A June 2010 study conducted by Titan Engineering concluded that OGS have a negligible impact on DFW ambient air quality and do not emit harmful levels of benzene and other pollutants."

The commission has not changed the rule in response to this comment. The reasoned justification for this rule action must demonstrate that all facilities which may use this authorization will be protective and meet all standards and guidelines. The analysis required must be conservative, but reasonable and representative of the potential facility emissions. The accepted methodologies for this analysis are purposefully conservative to ensure the evaluation covers multiple situations and scenarios and can predict impacts at any off-property location. It is always expected that subsequent monitoring results will be less than the predicted concentrations. If results were otherwise, the methods and tools used for all permitting would not be viable or relied upon for any permit or rule issuance.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented, "The timeline for implementation of this regulatory proposal is very short and does not account for the various Texas air emission studies that have been conducted and/or are ongoing according to a recent letter from Chairman Shaw dated June 11, 2010 to Region VI Administrator. Furthermore, the rule does not take into consideration various proposals at the federal level pertaining to oil and gas operations. As previously mentioned, there are several recent studies in the most dense drilling and production area of the Barnett Shale which have shown no air quality concerns attributable to these diverse, legislatively classified "insignificant emission" sources. Additionally, the proposal does not account for the ongoing Barnett Shale equipment and emission inventories for these insignificant sources. These studies should be used to guide the direction of the PBR and standard permit. There are several federal issues that will affect oil and gas operations that will be proposed or finalized. These include: The EPA is reviewing all the oil and gas 40 CFR Part 60 NSPS and 40 CFR Part 61 NESHAP standards (40 CFR Part 60 NSPS, LLL and KKK, in addition to 40 CFR Part 61 NESHAP HH and HHH) by consent order and will be proposing new rules starting January 2011 and finalized by November 30, 2011;The Existing Engine 40 CFR Part 61 NESHAP (ZZZZ) will be finalized August 10, 2010; The Greenhouse Gas Mandatory Reporting Rule- Subpart W covering oil and gas facilities will be finalized in September 2010; and The final Ozone NAAQS proposal will be finalized in August 2010. Moving ahead of the federal regulations too quickly could result in conflicting regulations and in the past TCEQ doing so has proven to be problematic."

The commission has not changed the rule in response to this comment. The PBR specifically contains cross references to other local, state, and federal requirements, therefore as EPA revises 40 CFR Part 60 NSPS and 40 CFR Part 61,

40 CFR Part 63 NESHAP standards, facilities will be required to comply with any additional applicable requirements. The other requirements which have been adopted by the commission are necessary to ensure an accurate estimate of emissions, minimization of potential releases, appropriate impacts evaluation, and practically enforceable records, sampling and monitoring. These requirements are included to ensure insignificance of these facilities. Without these reasonable demonstrations, the commission and public cannot be assured to be protective.

One hundred and thirty-four individuals recommended that the commission should increase the distance for a single registration from 1/4 to 1 mile.

The commission has not changed the rule in response to this comment. The 1/4 mile distance is consistent with historical site determinations and based on several years of oil and gas production site registrations. The 1/4 mile distance is a distance which consistently contains a majority of operationally dependent facilities under a common control. At this time there is no compelling evidence which suggests that expanding this distance to a mile is appropriate and necessary.

Pioneer stated "an OGS under this definition could result in a very large site. In Pioneer's Permian Basin operations, there are numerous wells and tank batteries adjacent and contiguous to one another, with no other operators in between, spread over large areas. Furthermore, not all of these facilities are operationally related (as required for a single PBR registration per subsection (b)(5)(C)) so if changes to these existing facilities are made, it would require multiple

§106.352 PBRs to be registered within the same OGS however, this appears to be in conflict with the language in the proposed rule. It would be helpful if the OGS site definition contained a reasonable cut-off point."

The commission has revised the language of this subsection (b) to specify and limit the scope of a registration. Registration is limited to a maximum of 1/4 mile, and is not expanded indefinitely due to piping connections, both specified in adopted subsection (b)(6)(D).

EPA recommended "a grid pattern spacing based on the minimum distance either based on actual spacing in some of the most densely packed areas of the Barnett Shale or the 1/4 mile distance separation. Whatever distance is the more conservative. EPA has issued guidance that indicates that sources potentially should be aggregated even if they are separated by a distance of greater than a 1/4 mile, and this is a case-by-case decision."

The commission has not changed the rule in response to this comment. Although operators may choose a grid spacing, field development throughout the state results in great variety of well and equipment spacing so the imposition of an artificial grid would not be realistic or appropriate for state-only authorizations. The commission emphasizes that aggregation for major source new source preconstruction and federal operating permits review may be required to evaluate different spacing as guidance and rules are promulgated under federal rules, and that the PBR and standard permit do not supersede any of those requirements.

Encana supports the commission's innovative approach to permitting OGS in the state of Texas and recognizes the need to update certain requirements of the PBR and the standard permit program. It is through this innovation that they believe the commission has been able to manage the thousands of air sources in the state while operating within the constraints of its limited resources.

Encana encourages the commission to continue this spirit of innovation, particularly with regard to effective alternative approaches to the currently proposed preconstruction review and NAAQS compliance demonstration, and the 1/4 mile grouping requirements.

The commission appreciates the support of the commenter of its efforts to provide innovative approaches to the regulation of this industry and has included additional options for registration timing, NAAQS demonstrations, and clarification of registration scope and the 1/4 mile distance scope.

NorTex "specifically endorses the comments made by these associations on the following issues: the importance of limiting the "daisy-chain" effect, problems associate with new BMP and control requirements and with the concept of establishing a *de minimis* threshold for individual facilities below which controls will not be required."

The commission partially agrees with the comments and has changed the rule in response. The commission has revised the language of subsection (b) to specify and limit the scope of a registration. A registration under this section will establish fixed boundaries to ensure no boundary creep as modifications occur at

the site, thus giving certainty to compliance demonstrations. The commission has clarified the boundaries expected of a registration based on comments to ensure that if only pipelines separate facilities over large distances (1/4 mile), even if the facilities are dependent on each other's operations, a single registration under this section will have definitive boundaries. Further details can be found in the section by section discussion that clarifies BMP and control requirements are voluntary. *De minimis* threshold values were developed from the most appropriate and most stringent modeling results and more information can be found in the section by section details.

TPA stated, "The basic applicability provisions should be restructured to avoid a PBR whose boundaries will shift project to project, thus creating an enforcement nightmare. See proposed §106.352(b)(5)(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 mile from the facilities associated with a project requiring registration under this section." (Emphasis added). This definition works well for the first project. However, an OGS boundary creep will occur over time as a new boundary is re-established to authorize new projects. Existing facilities would be dragged into one or more PBR authorizations claimed sequentially over time, depending on their location relative to each new project. If one or more of these sites are Title V sites, compliance becomes even more complex. The daisy-chain impact must be broken for facilities along a pipeline. The applicability provisions regarding a "site" must be clarified and fixed site boundaries must be established.

ETC states "This revised definition would have the benefit of addressing the possibility that OGS boundaries may shift over time. Proposed subsection (b)(5)(C) states: "A single PBR (or standard permit) registration shall include all facilities or groups of facilities at an OGS which are directly operationally related to each other and are located no greater than a 1/4 mile from the facilities associated with a project requiring registration under this section (or under this standard permit)." (Emphasis added). Under this provision, the boundaries of the OGS and the facilities authorized by the single PBR or Standard Permit could shift from project to project depending on where the 1/4 mile radius came to rest. This would create a compliance nightmare as the boundary of the OGS and facilities authorized by the PBR or Standard Permit would not remain fixed. The revised language presented by ETC provides a definition for OGS that describes the site with fixed boundaries for authorization purposes. In addition, under the language currently being proposed, the possibility exists for overlapping coverage, i.e., a particular area may fall within multiple 1/4 mile radii. The rule language should address this possibility and should make clear that in no event would a given area be subject to regulation under more than one PBR. ETC's proposed revisions, specifically new subparagraph (F), would remove this possibility by making clear that a given facility could not be considered as part of more than one OGS."

The commission partially agrees with the comments and has changed the rule in response. The commission has revised the language of subsection (b) to specify and limit the scope of a registration. As with the major source determination, all OGS facilities should be included. Unlike the federal guidance, this PBR is adopted to have a distance requirement of no more than 1/4 mile and the facilities, under a single PBR registration, should be operationally dependent. The commission considers that combinations of facilities and equipment, which are constructed

and operated together to handle materials or make a product to be related, require a single authorization. The commission has included an additional clarification to the scope of the registration based on the comments. A registration under this section will establish fixed boundaries to ensure no boundary creep as modifications occur at the site, thus giving certainty to compliance demonstrations. The commission has clarified the boundaries expected of a registration based on comments to ensure that if only pipelines separate facilities over large distances (1/4 mile), even if the facilities are dependent on each other's operations, a single registration under this section will have definitive boundaries. Furthermore, the boundaries of the registration become fixed at the time this section is claimed and registered. No individual facility may be authorized under more than one registration.

TPA comments "In this case, not only is TCEQ elevating the PBR from a facility to a site, but it is requiring the aggregation of different types of facilities within a 1/4 mile radius to be covered under a single PBR, under certain conditions. In the preamble, TCEQ justifies its expansion of the applicable coverage of the OGS PBR as follows: "The commission considers that combinations of facilities and equipments (sic) which are constructed and operate together to handle materials or make a product to be related and require a single authorization (see 35 TexReg 6942 (2010))." This statement of policy is carried out in the following proposed rule language: "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 1 mile from the facilities associated with a project requiring registration under this section (See proposed §106.352(b)(5)(C))." This is a stark departure from agency practice and policy. Previously, facilities at plant sites have been able to be authorized by multiple permits and PBRs, provided that certain conditions were met. For example, it is not unusual for some facilities at a site to be authorized by a Chapter 116, Sub30 TAC Chapter B permit and additional or small facilities to be authorized by a specific PBR, such as a flare, an emergency generator, an engine, and other discrete pieces of equipment."

Previous PBR §106.352 and Standard Exemption 66 as far back in history as 1986 included a number of common, related facilities. Many other industry segments (concrete batch plants, rock crushers, material handling, asphalt concrete plants, surface coating, aerospace manufacturing, etc.) have also been included in plant-wide or groups of dependent facilities under PBRs or standard permits. This combination of requirements has not ever impeded economic development and in fact follows THSC which empowers the agency to consolidate authorization were deemed appropriate: THSC, §382.0511, PERMIT CONSOLIDATION AND AMENDMENT, subsection (a), reads "The commission may consolidate into a single permit any permits, special permits, standard permits, PBRs, or exemptions for a facility or federal source." The commenter has not provided evidence that this approach would have a negative effect or is discriminatory. Finally, the commission points out that permitted sites may continue to use any specific PBR for which it is eligible and that any facility not in the scope of this revised PBR but co-located at a site may use any other available PBR.

TXOGA states "In the preamble to the proposed PBR, TCEQ references its August 2010 guidance document relating to defining what facilities constitute a "site" (entitled "Definition of

Site Guidance Document"). Based on the preamble discussion, proposed §106.352(b)(5)(C) and proposed standard permit subsection (b)(5)(C), TXOGA understands TCEQ's position to be that an OGS would in no instance include facilities located more than 1/4 mile apart, excluding piping and fugitive components. TXOGA also understands that the 1/4 mile limitation only applies if all of the requirements defining an OGS in proposed §106.352(b)(3) and proposed standard permit subsection (b)(3) are all met. With this understanding, TXOGA does not object in principle to proposed §106.352(a)(1) and §106.352(b)(5) and proposed standard permit subsections (a)(1) and (b)(5). TXOGA further understands, however, that the issues relating to aggregation are evolving, and believes that the issues would be appropriately addressed through TCEQ guidance rather than incorporation in to rule or standard permit language."

The commission partially agrees with the comments and has not changed in the rule in response. The commission appreciates the support and agrees that issues relating to aggregation are evolving. However, the commission strongly believes that the language in subsection (b) is imperative for industry and the public to have a clear understanding of what facilities are included in a registration.

TPA comments that they want to "emphasize that of paramount interest to the midstream/transmission segment is to ensure that the daisy-chain effect of overlapping 1/4 mile radius sites is broken, so that a pipeline that stretches over hundreds of miles is not considered a single site under the proposed PBR and standard permit. Such a consequence would be contrary to the "common sense notion of a plant" and would have a dramatic negative economic impact on the industry."

The commission agrees with the comment and has changed the rule in response. The commission has included an additional clarification to the scope of the registration based on the comments. Registration is limited to a maximum of 1/4 mile, and is not expanded indefinitely due to piping connections, both specified in subsection (b)(6)(D).

TPA further commented that, "The language proposed by staff to address the daisy-chain problem, however, may not effectively break the daisy-chain and is itself ambiguous. The language provides as follows: "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." The key term in this definition is "operationally separated," yet it is not defined. The result is that this determination will become a case-by-case judgment call, and the regulated entity and the permitting or enforcement staff of the TCEQ may not always be in agreement. An error in judgment on which facilities are or are not "operationally separated" could have significant consequences for the regulated entity and the agency and a significant amount of staff time will be taken up in making these decisions. Staff has suggested inserting a fixed distance criteria for the piping and fugitive emissions that would constitute an adequate breaking of the daisy-chain. This may be an effective, objective path toward resolution of this issue. It is important to point out here, however, that an effective resolution of this issue for the midstream/transmission segment of the industry may not be an effective resolution of the issue for exploration and production, given that different types and numbers of facilities are at issue for these two segments of the industry. Nonetheless, one effective way to re-craft this language is as follows. Of course, in all cases the definition of an OGS would also have to meet the criteria in subsection (b)(3) as we have revised it. This would ensure that an OGS would only include facilities that are, among other things, operationally dependent on one another. Accordingly, our suggestion of the above language assumes that our revisions to subsection (b)(3) are also made. Due to the significance of this provision, TPA would urge the TCEQ to republish the PBR with this revision so that all affected persons would be able to comment on the impact this new provision would have on their operations."

The commission agrees with these comments and has changed the rules accordingly. The commission has revised the language of subsection (b) to specify and limit the scope of a registration. The PBR is adopted to have a distance requirement of no more than 1/4 mile and the facilities, under a single PBR registration, should be operationally dependent. The commission considers that combinations of facilities and equipment, which are constructed and operated together to handle materials or make a product to be related, require a single authorization. The commission has included an additional clarification to the scope of the registration based on the comments. A registration under this section will establish fixed boundaries to ensure no boundary creep as modifications occur at the site, thus giving certainty to compliance demonstrations. The commission has clarified the boundaries expected of a registration based on comments to ensure that if only pipelines separate facilities over large distances (1/4 mile), even if the facilities are dependent on each other's operations, a single registration under this section will have definitive boundaries.

TPA also states "As currently structured, the geographic boundary of the applicable PER, defined as an Oil and Gas Site ("OGS"), shifts from project to project. Moreover, only one PBR may be claimed per OGS. See proposed §106.352(b)(5)(C) (providing that "{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"). Accordingly, facilities that must be aggregated under the proposed PBR include those facilities or groups of facilities that are "directly operationally related" and "located no greater than a 1/4 mile from the facilities associated with a project requiring registration under this section." This definition works well for the first project. However, an OGS-boundary creep will occur as new projects take place over time. As the OGS 1/4 mile radius boundary adjusts and creeps on a project basis to authorize new projects, existing facilities could be dragged into one or more PBR authorizations claimed sequentially over time, depending on their location relative to each new project. Layer on top of that the requirement that only one PBR may be used per OGS and the result is that a single facility can be authorized by sequential PBR registrations depending on the point in time in question. Compliance would be impossible to determine because identification of applicable PBRs for a particular facility would be administratively impracticable. For example, for years 1-3, Facility A is authorized under the PBR for Project 1; for years 4 - 5 Facility A is located within 1/4 mile of Project 2 and gets included the OGS and authorized by Project 2 PBR, and so on."

The commission agrees with the comments and has changed the rule in response. A registration under this section will establish fixed boundaries to ensure no boundary creep as modifications occur at the site, thus giving certainty to compliance demonstrations. The commission has clarified the boundaries expected of a registration based on comments to ensure that if only pipelines

separate facilities over large distances (1/4 mile), even if the facilities are dependent on each other's operations, a single registration under this section will have definitive boundaries.

EDF stated "There is some ambiguity about whether and how connecting piping or fugitive components referenced in this section are assigned to an OGS. The provision states that components "will not be considered when determining the 1/4 mile separation for registration." This statement should be clarified to ensure that such connecting components are included in the authorization for at least the closest OGS site. EDF also commented that it is not clear how one should measure the 1/4 mile separation between operationally related facilities. The TCEQ should more explicitly state this to avert any confusion as to how to measure the boundaries of an oil and gas site."

The commission agrees with the comments and has changed the rule in response. The commission has revised the language of subsection (b) to specify and limit the scope of a registration. Measurements of distance should be taken from the extent of the project's facilities or changes.

Sierra Club and 1 individual stated "The Single Registration for an Oil and Gas Site (OGS) is a Great Approach to Prevent Stacking. However, a "Site" should not be artificially limited by a distance measurement."

The commission respectfully disagrees with this comment and has not changed the rule. As a part of establishing a reasonable, standardized authorization

mechanism, the commission must set the scope of a PBR or standard permit authorization. With the diversity and uniqueness of the oil and gas industry's geographic spacing and pipelines, the commission determined that the only standardized, practical mechanism to establish minor source status was to include as a part of an registration scope, a distance limitation.

Representative Burnam supports only allowing one PBR to be claimed per site because it should prevent PBR "stacking" which has allowed operators to avoid emissions limits in the past.

The Sierra Club stated "We have two concerns with this provision. First, the proposed permits must include a definition for "directly operationally related." A clear definition is vital to provide fair notice and facilitate uniform application. Second, the absolute 1/4 mile distance cut-off for an OGS is inconsistent with TCEQ and EPA guidance for determining a site/source.1 Particularly with respect to oil and gas operations, which are diverse and can span significant distances, proximity cannot be the sole factor for a site determination; rather, a case-by-case analysis is necessary. We agree that operationally related facilities under common interest or control located 1/4 mile apart should always be aggregated as one source. However, consistent with TCEQ guidance, operationally-related facilities under common interest or control located more than 1/4 mile apart should be evaluated on a case-by-case basis to determine whether they constitute a single site for purposes of regulation."

The commission partially agrees with the comments and has changed the rule in response. The commission has changed the rule to include the phrase "operationally dependent" which has the obvious meaning of equipment which

must depend on another piece of equipment to operate. The commission has not relied solely on distance to establish the scope of a registration. Determinations for federal NSR and federal operating permits beyond the 1/4 mile and relying on the other relevant factors must continue to occur on a case-by-case basis. If these federal review requirements apply, a PBR or standard permit will not be the appropriate mechanism for authorization.

The Sierra Club also commented that, "The proposed permits should clarify where the 1/4 mile measure begins and ends. In theory, there are at least three methods TCEQ could employ for measuring proximity: 1) from the center; 2) from the outermost emission source; or 3) from the property line. As written, the proposed permits are unclear about where the 1/4 mile is measured (standard permit selected by an applicant may indeed be more than 1/4 mile apart, but at the same time the nearest emission points from each site could be well within the 1/4 mile distance. Furthermore, 1/4 mile is a relatively short distance given the expansive nature of OGS. To truly be inclusive, the 1/4 mile distance should be measured between any two emission points to determine whether they are included in a single OGS registration, not between two theoretical center points."

TRAED and 5 individuals, ABCA, Sierra Club, Lone Star Chapter, Earthworks Texas Oil and Gas Accountability Project commented that, "The 1/4 mile separation for a single oil and gas registration should be determined from the outermost equipment" and "encompass all equipment bounded by the outermost equipment at a location. Rather than finding an arbitrary "center" of a site, and drawing 1/4 of a mile from that point, look at the entire site and draw around the outermost equipment. This has the added benefit of preventing industry circumvention of the new rule by establishing new “sites” outside of an OGS to avoid more stringent permitting standards."

The commission has changed the rule in response to the comment. The commission has revised the rule to clarify that the distance measurement for the scope of the registration is based on the outer boundaries of a project as all of those sources contribute to emissions.

Devon commented "The proposed PBR includes language that appears to aggregate emissions from OGS with facilities located on contiguous or adjacent properties, under common interest and control, and designated under the same two-digit SIC code within 1/4 mile. Since piping connections and fugitive components cannot be the basis for aggregating OGS within 1/4 mile, a daisy chain effect of aggregation of emissions is avoided and the OGS definition is more consistent with the "common sense notion of a plant" from the 1979 D.C. Circuit Alabama Power decision."

The commission agrees with this comment and has changed the rule in response. Language has been added to clarify and appropriately limit the scope of registration.

HCPHES stated "A more clear definition is needed with regard to the facilities within the mile radius of a project. The words "directly operationally related" will bring on a wide interpretation. Specifically, give examples of facilities to be included such as pipelines, well heads, tank batteries, etc., in the PBR and examples for points of reference such as emission points, new unit/facility, etc. We recommend that the examples are sited as not all inclusive as to allow the enforcement of new technologies that come online for operationally related matters in the future."

The commission agrees with this comment and has changed the rule in response. Language has been added to clarify the rule language with all respects to registration scope. The commission also emphasizes that all types of facilities, and groups of operationally dependent facilities, as listed in subsection (c) are covered by this PBR, in any combination.

EPA commented that it "does not believe the 1/4 mile limitation in §116.620(b)(5)(C) and (6)(A) and §106.352(b)(5)(C) and (6)(A) is appropriate in the "proximity" component for the aggregation of facilities that should be included as part of the permitted OGS as defined in subsection (b)(3). TCEQ is reminded that in a memo dated September 22, 2009, Gina McCarthy withdrew the January 12, 2007 guidance memorandum entitled "Source Determinations for Oil and Gas Industries." The aggregation of facilities should be done in accordance with 40 CFR §52.21(b)(6). Permitting authorities should rely foremost on the three regulatory criteria for identifying emissions activities that belong to the same "building", "structure", "facility", or "installation." These are: 1) whether the activities are under the control of the same person (or person under common control); 2) whether the activities are located on one or more contiguous or adjacent properties; and 3) whether the activities belong to the same industrial grouping. We acknowledge that TCEQ has added these three criteria in §116.620(b)(3) and §106.352(b)(3). Whether or not a permitting authority should aggregate two or more pollutant emitting activities into a single stationary source for purposes of NSR and

Title V remains a case-by-case decision in which the permitting authorities retain the discretion to consider the factors relevant to the specific circumstances of the permitted activities. After conducting the necessary analysis, it may be that in some cases, "proximity" may serve as the overwhelming factor in a permitting authority's source determination decision. However, such a conclusion can only be justified through reasoned decision making after examining whether other factors are relevant to the analysis on a case-by-case basis."

The commission partially agrees with the comments and has not changed the rule in response. The commission has not relied solely on distance to establish the scope of a registration. Determinations for federal NSR and federal operating permits beyond the 1/4 mile and relying on the other relevant factors must continue to occur on a case-by-case basis. If these federal review requirements apply, a PBR or standard permit will not be the appropriate mechanism for authorization.

ETC commented that as currently proposed, the rules would prevent a facility from claiming multiple PBRs. There is no reason to suddenly restrict the use of PBRs (such as are provided for in §106.492 and §106.512) that oil and gas facilities have been utilizing for years. There is no evidence that TCEQ has concluded that such PBRs have been ineffective or insufficiently protective; and in the event that this was true, the proper remedy would be to amend the allegedly flawed PBR. The fact that PBRs in §106.492 and §106.512 will continue to be available to all segments of the economy other than the oil and gas sector demonstrates that there is no problem with the protectiveness of the PBR requirements. That being true, there is no reason why these authorizations should now be made unavailable to the oil and gas industry. It is unprecedented for TCEQ to single out one portion of Texas business and say it may no longer use PBRs while all other businesses may continue to do so. Such an approach is arbitrary and, more importantly, would place the Texas oil and gas industry at a competitive disadvantage with other businesses generally, and out-of-state businesses in particular. "In addition, authorization at the site level rather than the facility level is not supported by statutory authority. The proposed PBR will impose requirements applicable at the site level instead of the facility level. This action is not supported by statutory authority. THSC, §382.05196, which pertains to PBRs, provides that the "commission may adopt permits by rule for certain types of facilities if it is found on investigation that the types of facilities will not make a significant contribution of air contaminants to the atmosphere." "Facility" is defined in the THSC, §382.003(7) as "a discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a stationary source, including appurtenances other than emission control equipment." Accordingly, while there is statutory authority to impose PBR requirements at the facility level, there is no similar authority for imposition of PBR requirements at the site level."

TPA stated "When asked about this policy, Staff confirmed that it was indeed new. Staff acknowledged that the practice at the agency has been to allow multiple authorizations at a single plant site. TCEQ's proposal incorporating this new policy for OGS puts the oil and gas industry at a disadvantage vis a vis other types of industrial sites in Texas that continue to be able to authorize facilities by use of multiple authorizations, so long as certain threshold emission levels are not exceeded and certain conditions are met. Staff explained that this policy would apply on a going-forward basis to the oil and gas industry and that it was not known whether or how it would be applied to other types of industries in Texas, such as refineries, chemical plants, manufacturing plants, etc. If this new policy is maintained in this PBR, the

Commission would be simultaneously amending the Texas Clean Air Act, significantly changing the scope of PBR authorizations, and unjustifiably treating the oil and gas industry differently from all other industries in Texas." Additionally, "These PBRs certainly do not establish any precedent for the type of PBR proposed here. The simple fact is that the TCEQ's statutory authority only allows it to issue a PBR for types of facilities that will not make a significant contribution of air contaminants to the atmosphere. That authority does not allow the agency to use a PBR to cover an entire site that represents a collection of multiple types of facilities and may be scattered over a 1/4 mile radius. TPA would urge TCEQ to choose a more considered path, abandoning site-wide applicability of a PBR or seeking legislation that would authorize this type of permitting scheme. TPA believes a non-site-based regulatory scheme can be developed either at the agency or through legislation that would create a permit mechanism that could achieve the TCEQ's goals of protectiveness while protecting the integrity of PBR authorizations. TPA offers to work with TCEQ in developing either such program. We acknowledge that any such further development would require additional time, but we think it is more important to get it right than to just get it done."

The commission has not changed the rule in response to these comments. All oil and gas facilities that are operationally dependent at a site must be authorized under one PBR registration. This oil and gas PBR cannot be used to authorize any facilities at a site that are operationally dependent on facilities at the site already authorized under standard permits or NSR Permits, with the exception of planned MSS.

The standard permit application process includes a protectiveness review, specific stringent requirements, and BACT demonstration that are not required by the PBR.

It was the intent of the commission to allow PBRs to be used at sites with NSR Permits The reason why PBRs were allowed to be used at sites with NSR Permits is because they were meant as a way to make a small change at a large site without the applicant having to go through the more complex and costly permit amendment process. The idea was that the small change at the PBR level limits would result in an insignificant amount of air emissions, which would not require a permit amendment review. The permit amendment process requires an in depth case-by-case analysis with a protectiveness review, air emissions modeling as applicable, BACT demonstration, and public notice. Truly small changes will still be allowed to be made at NSR permitted sites under PBRs §106.261 and §106.262, but not PBR §106.352.

Unintended problems have resulted from allowing the use of PBRs at NSR permitted sites. Each PBR claim must have emissions less than the 25/250 tpy PBR limits of §106.4(a)(2); however, as stated in §106.4(a)(4), NSR permitted sites that have been to public notice, are allowed to use PBRs to authorize emissions from new equipment and changes at the site with no limit to the total amount of emissions. This poses a problem in that multiple small increases of less than the 25/250 tpy PBR limits over time could add up to a significant amount.

There are multiple problematic aspects to this matter. First, air permit applicants have the choice of whether they wish to incorporate PBR authorized sources into their NSR Permit or reference them. If referencing is chosen, a site could be largely covered under a PBR that is a much larger site than was ever intended to be covered under a PBR. Because the PBR was meant for insignificant sources, the oil and gas PBR lacked a protectiveness review and BACT requirement.

A second aspect to the use of PBRs for small changes at NSR permitted sites is since each project increase is small, PSD/NNSR review may never be triggered. This means a site could potentially be major, but have not gone through PSD/NNSR review.

A third aspect to this is if public notice has occurred for an NSR permit and the NSR permit expires or is voided, the applicant may use PBRs freely, avoiding a protectiveness, BACT, and PSD/NNSR requirements.

A fourth aspect is that it is hard to tell what equipment/processes are authorized at a site if different pieces are authorized under different authorizations. This causes confusion for the applicants as well as agency staff.

Many examples can be found in which one site is authorized by a combination of

permit authorizations including Standard Exemptions, PBRs, standard permits, and case-by-case NSR permits. The following examples illustrate the need for one PBR authorization per site for all oil and gas dependent equipment/processes.

Natural gas processing plant, Site A in TCEQ Region 7 - Midland, is currently authorized under a combination of Standard Exemptions and PBRs. Site A underwent public notice with NSR construction Permit Number 9990 originally issued in 1986 that has since been voided. Six compressors with an estimated 961 tpy NO_X and 233 tpy CO, glycol dehydration equipment, and a de-methanizer are authorized under Standard Exemptions. An amine sweetening unit is authorized under PBR Number 47931 (issued in 2001) and an acid gas flare is authorized under PBR Number 74189 (issued in 2004). Unregistered liquid storage tanks are also represented to be at the site. With PBR Number 93903, issued in 2010, new engine emissions were authorized at the site. The applicant provided demonstration that PSD review has not been triggered for this site.

Site B in TCEQ Region 7 - Midland is currently authorized under PBR Number 32854, which has been revised several times over the years for various reasons including engine replacements; registering of condensate, produced water, and flare-knockout tanks; and re-routing of compressor blowdown emissions. The site was originally authorized and underwent public notice with NSR construction Permit Number 19139 originally issued in 1989 that has since been voided. The late 2009 revision of PBR Number 32854, which authorized the emissions from an

added flare knock-out tank, indicates that the total site-wide emissions are 59 tpy VOC, 97 tpy NO_X, and 154 tpy CO.

Site C in TCEQ Region 7 – Midland has been issued a large amount of various permit types including PBRs, standard permits, NSR Construction Permits, and Standard Exemptions. The site is currently undergoing an amendment to Construction Permit 2211A. PBR Numbers 40188 and 30079 and a Standard Permit Number 39456 have been revised numerous times for reasons including engine replacements, tank replacements and additions, a separator addition, and fugitive component additions.

Site D in TCEQ Region 7 - Midland has been issued a large amount of various permit types including PBRs, NSR Construction Permits, PSD Permits, and Standard Exemptions. Due to the large amount of authorizations for the same site, they do not provide a clear picture of what equipment/processes are currently at the site and what the current emission points are.

Site E in TCEQ Region 11 - Austin has authorized one turbine under PBR Number 82531 and one under an NSR Permit Number 8366. The one authorized under the NSR permit was originally authorized under a PBR and then incorporated. Because of the dual authorization for two similar units, if the applicant wishes to make a change to both turbines, they have to revise both authorizations.

Site F in TCEQ Region 7 - Midland is currently authorized under PBR Numbers 78741 and 86491 and NSR Permit Number 1324A (including compressors and tanks). The applicant is currently seeking to combine PBR authorizations. They plan to void PBR Number 86491 and revise PBR Number 78741 to authorize MSS and emergency generator emissions.

Site G in TCEQ Region 4 - DFW Metroplex is currently authorized under Standard Permit Number 72937 and consists of multiple engines, dehydration and sweetening units, and various tanks. The site emissions include 45 tpy VOC, 244 tpy NO_X, and 242 tpy CO. The site has been issued PBR Numbers 77607 and 51449, Pollution Control Standard Permit Number 51030, and NSR Construction Permit Number 72937 to authorize emissions from various sources including engines and tanks; these authorizations have since been voided. The 2008 revision of Standard Permit Number 72937 consolidated all emissions except those from one compressor authorized under NSR Permit Number 73351. The NSR Permit was voided in 2009 and the compressor was represented to have been removed.

Site H in TCEQ Region 3 - Abilene has been issued a large amount of various permit types including PBRs, NSR Construction Permits, PSD Permits, and Standard Exemptions. The site has a large amount of emissions; NSR Construction Permit Number 20660 authorizes over 400 tpy VOCs, 1,500 tpy NO_X, 550 tpy CO, and 200 tpy SO_2. PBRs have been used to make changes at the site, most recently in 2010 under PBR Number 92308 under §106.261, and §106.262.

Site I in TCEQ Region 8 - San Angelo has been issued a large amount of various permit types including PBRs, standard permits, NSR Construction Permits, PSD Permits, and Standard Exemptions. Most recently PBR Numbers 89323 and 90828 have been used to add engines to the site. Due to the large amount of authorizations for the same site, it is difficult to figure out what equipment/processes are currently at the site and how each emission point is authorized.

Finally, the commission respectfully disagrees that combining requirements for common, dependent facilities is illogical and unfair. Previous PBR §106.352 and Standard Exemption 66 as far back in history as 1986 included a number of common, dependent facilities. The revisions to this PBR only take this historical approach one step further by including necessary updated requirements for engines and flares, as well as all other previously authorized oil and gas facilities. The commission is also committed to updating the individual PBRs for engines and flares immediately upon completion of this rule project to ensure fairness to all industries which use these authorizations in Texas.

ETC stated "It is illogical and unfair to eliminate oil and gas facilities' ability to use other PBRs. The industry needs to be able to combine PBRs. If TCEQ eliminates that ability, many oil and gas facilities will need individual NSR authorizations. This will seriously limit economic growth in the oil and gas sector. Accordingly, PBR §106.352 should be revised to provide that it does not apply to those components already covered by the PBRs in §106.492 (flares) and §106.512

(engines and turbines), or alternatively provide that use of the PBR §106.352 does not preclude use of other PBRs. The TCEQ should eliminate the currently proposed discriminatory language that restricts the oil and gas industry from using other PBRs."

The commission respectfully disagrees with this comment and has not changed the language in response. The commission respectfully disagrees that combining requirements for common, dependent facilities is illogical and unfair. As stated in a previous response, previous PBR §106.352 and Standard Exemption 66 as far back in history as 1986 included a number of common, dependent facilities. Many other industry segments (concrete batch plants, rock crushers, material handling, asphalt concrete plants, surface coating, aerospace manufacturing, etc) have also been included in plant-wide or groups of dependent facilities under PBRs or standard permits. Finally, the commission points out that permitted sites may continue to use any specific PBR for which it is eligible and that any facility not in the scope of this revised PBR but co-located at a site may use any other available PBR.

TPA argues that "The Legislature's meaning is clear. A PBR may not be issued other than to authorize a discrete piece of equipment. If the Legislature had intended a broader application for a PBR, e.g. to sites, then it could have said so. Where the Legislature intended to provide that a particular permit or authorization was to cover multiple facilities at a site, it clearly used language broadening the scope of the authorization. For example, in describing the coverage of a Title V permit, the Legislature provided that the commission may issue "a single federal operating permit or preconstruction permit for multiple federal sources or facilities located at the same site." (See THSC, §382.051(b)(5).) Similarly, in defining a federal source for Title V or Title IV purposes, the Legislature stated: "a federal source" means "a facility, group of facilities, or other sources ..." (see THSC, §382.003(7)). This demonstrates that in drafting the TCAA, the legislature knew how to express its intent that a particular permit or authorization can or must be used to authorize sources of air contaminants more broadly than isolated facilities, i.e. pieces of equipment. The fact that it chose not to do so in the PBR context is dispositive: the agency simply has not been given any authority by the Legislature to apply a PBR broadly to a "site." An examination of PBR authorizations reveals that in some contexts the TCEQ has established plant-wide conditions that must be met for a PBR. Notably, in many of these instances, the PBRs are related to aggregate or pavement activities. In this context, dust suppression is the issue of concern and is typically achieved by periodic sprinkling of in-plant roads. The in-plant roads are considered the "facility," or the source of the air contaminant (dust or particulate matter), and are subject to the requirement to be periodically sprinkled with water or chemicals. These authorizations are distinguishable from the proposed OGS PBR in that under the OGS PBR multiple unlike-kind facilities within a 1/4 mile radius will be aggregated and authorized as a single site under a single PBR, as compared to a plant-wide condition to suppress dust from in-plant roads. Other PBRs that appear to authorize a plant site, such as §106.124, Pilot Plants and §106.224, Aerospace Equipment and Parts Manufacturing, are equally distinguishable. The Pilot Plant PBR is only available for plants that are prototypes of larger plants or for testing the manufacturing or marketing potential of a product and cannot extend for a period longer than 5 years. The Aerospace Equipment PBR does not require that all facilities at the site be covered under a single PBR (See e.g., §106.224(1) ("{t}his definition excludes those operations specifically authorized by other permits by rule"). The TCEQ has no statutory authority to establish a PBR as a site-wide authorization tool. The TCEQ is, in fact, restricted to using a PBR as a facility-based authorization. The Legislature has clearly spoken on this issue. In describing the TCEQ's general authority to issue air permits under the Texas Clean Air Act, the Legislature specifically states: "{t}he commission may issue a permit . . . to construct a new facility or modify an existing facility . . .." (THSC, §382.051(a) (Emphasis added.).) That section goes on to state, in pertinent part, that "No assist in fulfilling its authorization provided by Subsection (a), the commission may issue . . . a standard permit for similar facilities . . . {and} a permit by rule for types of facilities that will not significantly contribute air contaminants to the atmosphere . . .." (THSC, §382.051(b) (Emphasis added).) The Legislature specifically addresses the TCEQ's authority to develop PBRs in THSC, §382.05196, which states: "the commission may adopt permits by rule for certain types of facilities if it is found on investigation that the types of facilities will not make a significant contribution of air contaminants to the atmosphere." (Emphasis added.) Importantly, as mentioned above, "facility" is defined as "a discrete or identifiable structure, device, item, equipment, or enclosure that constitutes or contains a stationary source, including appurtenances other than emission control equipment." (THSC, §382.003(6).) A "facility" is not a "site" — a facility is a specific, discrete building or piece of equipment. The TCEQ has no authority to transcend this clear statutory authority to create a site-based authorization from one that is clearly facility-based."

The commission respectfully disagrees with this comment and has not changed the rule. Since 1972, standard exemptions (now known as PBRs) have been developed for either single facilities or combinations of dependent facilities. This rule package is consistent with that historical approach, and if the legislature disagreed with that direction would have subsequently passed amendments to statutes toward that end. Instead, in 1999, the legislature passed THSC, §382.0511 which

empowers the agency to consolidate authorization where deemed appropriate: See THSC, §382.0511, Permit Consolidation and Amendment. "(a) The commission may consolidate into a single permit any permits, special permits, standard permits, PBRs, or exemptions for a facility or federal source." Finally, the commission points out that permitted sites may continue to use any specific PBR for which it is eligible and that any facility not in the scope of this revised PBR but co-located at a site may use any other available PBR.

TXOGA expressed concerns with how the "TCEQ will implement the concepts in proposed §106.352(a)(1) and §106.352(b)(5) and proposed standard permit subsections (a)(1) and (b)(5), which provide that only one PBR or one standard permit may be claimed or registered at each OGS. TXOGA is specifically concerned with how TCEQ intends to require that particular facilities must be aggregated into a single OGS authorization. TXOGA requests that TCEQ provide assurances that the requirement will not be used to aggregate facilities into a single PBR or a single Standard Permit if the facilities should not reasonably be aggregated together."

The commission does not agree with this comment and has not change the rule. The commission's intent is not to arbitrarily aggregate multiple, nondependent facilities separated over large distances under a single PBR. As always, regulated entities may provide detailed information on any given project or combination of facilities regarding appropriateness of using a single PBR or a combination of other authorizations.

ETC stated the "TCEQ has proposed requirements for the Texas oil and gas industry that are not equitable with other Texas industries. Examples of provisions in the PBR that would unfairly single out the oil and gas industry for discriminatory treatment include the concept of a single PBR authorization for an entire site, which is a requirement that is not currently applied in other industries, e.g., chemical plants and refineries."

Targa commented that, "the draft PBR §106.352 requires authorization of engines, flares, and generators under §106.352 rather than as previously authorized under the flare PBR §106.492, engine PBR §106.512, and standby engine PBR §106.511. As singled out, the oil and gas industry will be the only industry not allowed to use these PBRs to authorize these types of sources. In addition, the requirements for these sources in §106.352 are inherently more severe than the current §§106.492, 106.511, and 106.512. Therefore, oil and gas operations will have to comply with more restrictive emission limitations and requirements than other industries with similar sources. Targa believes this is punitive and recommends allowing engines, flares, and generators to be authorized under the same PBRs as other industries. Targa requests the TCEQ continue to restrict the use of §106.352 to the emissions sources currently regulated as such: Any oil or gas production facility, CO_2 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."

TPA argued "There is no need to take a radical new approach to the PBR such that a simple, easy-to-understand rule is cast aside and replaced with a 45-page document that is extremely complicated, is difficult to interpret, imposes a broad array of detailed control requirements that should not be applied to insignificant sources, involves an inordinate amount of case-by-case review, and in some instances even requires entities to obtain approval from agency staff prior to undertaking a new project. Nor is it justification for the imposition of requirements that would be stricter than those imposed by federal law and that would unfairly single out the Texas oil and gas industry for treatment that would be stricter than that accorded to other industries in the State. Given current economic difficulties and the absence of any demonstrated health threat from oil and gas facilities, this is no time to rush into a wholesale re-write of the rules governing oil and gas production. The imposition of a new, untested, and potentially unworkable regulatory program in the Texas oil and gas industry is unwarranted, and it could have a severe negative impact on the oil and gas sector in this State and therefore on the budget and economy of the State. We would be very interested in working with the agency to develop the existing proposal into one that will result in requirements that assure continued protection of public health and the environment yet provide ease in implementation and certainty in compliance and enforcement."

ETC stated the "TCEQ has proposed requirements for the Texas oil and gas industry that are not equitable with other Texas industries. Examples of provisions in the proposed PBR that would unfairly single out the oil and gas industry for discriminatory treatment include the concept of a single PBR authorization for an entire site, which is a requirement that is not currently applied in other industries, e.g., chemical plants and refineries."

Devon stated "The proposed revisions to the PBR and standard permit place a disproportionate, inequitable burden on the oil and gas industry to achieve a minimal reduction of air emissions in the state of Texas. To date, Devon is unaware of TCEQ's consideration of any rules on an equivalent magnitude that mandate emission reductions from other sources or industry sectors emitting similar types and quantities of pollutants. For instance, other industries in the state of Texas will be able to continue their use of the existing, less stringent PBRs for engines and flares. As such, TCEQ's actions appear to be arbitrary and capricious."

The commission respectfully disagrees with parts of these comments and has updated the rule in certain areas. Previous PBR §106.352 and Standard Exemption 66 as far back in history as 1986 included a number of common, dependent facilities. Many other industry segments (concrete batch plants, rock crushers, material handling, asphalt concrete plants, surface coating, aerospace manufacturing, etc) have also been included in plant-wide or groups of dependent facilities under PBRs or standard permits. This combination of requirements follows THSC, §382.0511 which empowers the agency to consolidate authorization were deemed appropriate. The groups of dependent oil and gas facilities in close proximity (1/4 mile) under common control on the same property is an appropriate mechanism for authorization and is on a practical basis consistent with thousands PBR registrations accepted currently and allows a comprehensive evaluation of insignificant and protective emissions.

The commission has numerous examples of inappropriate stacking of Standard Exemptions, PBRs, and standard permits at NSR permitted sites, where the

facilities are operationally dependent on each other. The incentives built into the revised PBR include reduced fees and more flexible deadlines for registrations under the lower limits of Level 1 of the PBR. In addition, if new project increases are offset by other decreases at a registered oil and gas operation, the protectiveness review is limited and simplified. The commission is also committed to updating the individual PBRs for engines and flares immediately upon completion of this rule project to ensure fairness to all industries which use these authorizations in Texas.

Devon commented "the proposed revisions to the PBR and standard permit place a disproportionate, inequitable burden on the oil and gas industry to achieve a minimal reduction of air emissions in the state of Texas. To date, Devon is unaware of TCEQ's consideration of any rules on an equivalent magnitude that mandate emission reductions from other sources or industry sectors emitting similar types and quantities of pollutants. For instance, other industries in the state of Texas will be able to continue their use of the existing, less stringent PBRs for engines and flares. As such, TCEQ's actions appear to be arbitrary and capricious."

The commission respectfully disagrees with the commenter that these rules "place a disproportionate, inequitable burden on the oil and gas industry to achieve a minimal reduction of air emissions." The potential of extremely high emissions from an OGS is possible, and has been seen at hundreds of sites in Texas. The growing use of the FLIR GasFindIR camera has allowed the commission's technical staff to characterize and assess emissions from OGS more accurately. Since 2006, the mobile response team (MRT) has conducted more than 25

monitoring trips to study these emission sources across the state of Texas including trips to Corpus Christi, Point Comfort, Ingleside, Houston, Pearland, Freeport, Texas City, Mont Belvieu, Beaumont, Port Arthur, Midland, Odessa, Longview, Mexia, Franklin, and Fort Worth. Further work by regional staff has established that natural gas and oil emissions are not confined to these areas, as they have been visualized, measured, and/or investigated in all geographic locations of Texas. The commission is still in the process of characterizing these emissions, but the use of the GasFindIR camera in other commission applications has led to the understanding that emissions have been historically underreported. The commission is also committed to updating the individual PBRs for engines and flares immediately upon completion of this rule project to ensure fairness to all industries which use these authorizations in Texas.

TXOGA expressed concerns over "eliminating the use of §106.352 in the future at an OGS that has a 116.111 authorization in (a)(1). The proposal states that industry would no longer be able to use §106.352 at a site with a 116.111 authorization, but other PBR's such as §106.261 and/or §106.262 could be used to authorize some facilities. Our concern is when the requirements of PBR's §106.261 and/or §106.262 cannot be met, the only alternative would be to open the 116.111 permit to authorize these facilities, which could take a year or more. Permit limitation concern example: fugitive components (valves, flanges, connectors) are needed to be constructed for an integrity/safety concern at a site that has a 116.111 permit. The gas within these fugitive components contains H_2S, and the components are to be located nearer then 300 feet to a property line. PBR §106.261 does not allow an (L) limit of < 200 milligrams per cubic meter. H_2S, as per the table in §106.262, has an (L) limit of 1.1. PBR §106.262 could also not be used as the gas contains H_2S and (a)(4) of §106.262 requires facilities with H_2S to be located at least 300 feet from a property line. Small changes such as this that do not meet the requirements of §106.261 and/or §106.262 are very common at OGS's that have a 116.111 permit and have been historically authorized through §106.352, which is then rolled into the 116.111 permit at the time of renewal. Another concern is the limits of §106.261 to 6 lb/hr of the chemicals listed and 1 lb/hr for other chemicals with an (L) limit greater than 200 milligrams per cubic meter and §106.262 limits to 5 TPY and E, where E = L/K. These two PBRs are very limiting and if the project meets the protectiveness requirements, then it should be allowed to use §106.352. It is requested that the future use of §106.352 along with other applicable PBR's be allowed at OGS's that have §116.111 permit authorizations."

The commission has not changed the rule in response to this comment. Consistent with all other industries regulated in Texas, changes or additions at permitted (§116.111) groups of facilities should use the most common of all PBRs, §106.261 and §106.262. The example described concern that piping components needing to be added at a site would not meet the distance or emissions limits of those PBRs. The commission emphasizes the importance of the speciated contaminant-specific limitations of these PBRs to ensure protection of public health and welfare as well as compliance with ambient air quality standards (such as 30 TAC Chapter 112 for H_2S). Maintaining consistency of requirements for all industries in Texas when at a site with a NSR permit provides certainty for the public and regulated entities. The commission's clear intent with the revised §106.352 is to authorize a combination of dependent equipment which, when combined, continues to be insignificant. Minor changes at otherwise permitted sites should use other PBRs

and later consolidate those authorizations into the permit at the next amendment or renewal. In addition, the commission has numerous examples of inappropriate stacking of Standard Exemptions, PBRs, and standard permits at NSR permitted sites, where the facilities are operationally dependent on each other.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA stated that the "TCEQ explains in the preamble to the proposed PBR and the "Hierarchy of Air Authorizations" section of the proposed standard permit, that PBRs are designed for facilities with insignificant emissions.20 (emphasis added) TCEQ also explains that standard permits are more complex than PBRs, but do not require a case-by-case review or trigger federal pre-construction authorization.21 Based on the low levels of emissions from OGS, TCEQ justifies the proposed PBR and proposed standard permit as providing an "updated, comprehensive, and protective authorization for many common OGS and facilities in Texas." TXOGA wholeheartedly agrees with TCEQ's conclusion that the appropriate mechanism of authorization for many common OGS facilities is either a PBR or a standard permit. TXOGA believes that the above-discussed air monitoring and toxicological studies demonstrate that the existing PBR and standard permit are still an appropriate authorization mechanism for many common OGS facilities. Oil and gas production operations at a typical OGS are fairly simple and require a limited amount of equipment."

The commission partially agrees with the comment and has not changed the rule. The commission appreciates the comments on the hierarchy of air authorizations and the support for maintaining an oil and gas PBR and standard permit. The commission respectfully disagrees, however that all operations are "fairly simple and require a limited amount of equipment." Based on previously registered

groups of facilities under §106.352 and the oil and gas standard permit, the number and combinations of facilities are extensive and vary in size, quantity, and materials handled or treated. The adopted PBR and Standard permit account for these variations to provide flexibility while ensuring overall emissions limits, protectiveness, and practical enforceable compliance requirements.

TPA states "the first line of subsection (a)(1) provides that "{o}nly 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 is an absolute requirement, and it does not take into account historic authorizations that will remain in effect until modifications occur that result in a change in character or an increase in the quantity of emissions. It also does not take into account the acquisition of new assets that could occur within a 1/4 mile range that are historically authorized or could be authorized by a separate PBR. There needs to be regulatory language that recognizes this fact -- that both the new PBR and historic authorizations will remain valid and will authorize specific pieces of equipment until there is a change or modification to the historic assets that will require a re-authorization under the new PBR."

The commission agrees with the comment and has changed the rule in response. The wording in §106.352(a)(1) did not clearly iterate that existing, unchanged facilities retain their historical authorization for production-related emissions. The commission has clarified in subsections (a), (b), and (l) that existing, unchanged facilities can maintain their historical production authorizations.

TPA states "provisions must be established transitioning sites from multiple PBRs to a single

PBR."

The commission appreciates this comment and has established an effective date of April 1, 2011 or January 5, 2012 for all new projects, and further clarified other requirements in subsections (a) and (b) to ensure that the applicability of the revised conditions should not generally require specific changes to existing, unchanged production facilities in Texas and that those facilities can maintain their previous Standard Exemption or PBR authorizations (except for the newly authorizable planned MSS which is discussed later and not triggered until January 5, 2012). Until a company makes a decision to invest capital to make physical or operational changes to a facility or group of dependent facilities, the new requirements are not applicable, thus the transition of authorization is under the control of any regulated entity and will be considered as a part of any future business decision.

NorTex "endorses the following changes made in response to concerns raised by NorTex and other entities such as the Texas Pipeline Association to phase in or limit the application of control technology in the Standard Permit and PBR and allow the use of other authorizations for facilities not "directly operationally related to each other"."

The commission agrees with the comment and has changed the rule in response. The rule has been clarified to limit registration applicability to operationally dependent facilities and emphasize that no control technologies are mandated in the PBR. Furthermore, other types of facilities may use other PBRs as listed in

subsection (d).

TXOGA commented that they are "specifically concerned with how TCEQ intends to require that particular facilities must be aggregated into a single OGS authorization. TXOGA requests that TCEQ provide assurances that the requirement will not be used to aggregate facilities into a single PBR or a single Standard Permit if the facilities should not reasonably be aggregated together."

The commission agrees with the comment and has changed the rule in response to this and similar comments expressing concern over arbitrary aggregation of facilities by adding the phrase operationally dependent as well as clarifying that piping connections would not extend the 1/4 mile distance restriction.

ETC commented that, "the term "operationally related," used in subsections (a)(1), (b)(5)(A), and (b)(5)(C) of the proposed PBR, and in subsections (a)(1) and (b)(5)(C) of the Standard Permit, should be changed to "operationally dependent." The term "operationally related" is very vague and subject to varying interpretations. Moreover, the use of that term in the PBR and the Standard Permit would result in improperly overbroad groupings of facilities. The term "operationally dependent" is narrower and, as such, would eliminate the overbroad grouping problem that would be created by use of the term The term "operationally related," used in subsections (a)(1), (b)(5)(A), and (b)(5)(C) of the proposed PBR, and in subsections (a)(1) and (b)(5)(C) of the Standard Permit, should be changed to "operationally dependent." The term "operationally related" is very vague and subject to varying interpretations. Moreover, the use of that term in the PBR and the Standard Permit would result in improperly overbroad groupings of facilities. The term "operationally dependent" is narrower and, as such, would eliminate the overbroad grouping problem that would be created by use of the term "operationally related." Use of the term "operationally dependent" would result in the creation of coherent and sensible groupings for purposes of PBR coverage. The term "operationally separated" is used once in the proposed PBR and Standard Permit, in the second sentence of subsection (b)(5)(C): "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." This sentence is clearly intended to remedy the "daisy chain" problem, i.e, the possibility that a single pipeline stretching for miles might improperly be considered to be a single "site" under the PBR or Standard Permit. ETC agrees that it is important to ensure that the rule language does not lend itself to such an unreasonable interpretation. However, in order to qualify for this "anti-daisy chain" provision, facilities by definition would have to be "operationally separated." This is a vague term that could be interpreted to apply only to facilities that have no connection whatsoever to one another. Operational "independence" is more common than operational "separation" and the use of the former term would more accurately capture the likely intent of TCEQ staff: to ensure that facilities, whose only relationship with one another is their placement along the same length of pipe, are not pulled into the same "site" definition."

The commission agrees and has changed the rule in response to this and similar comments expressing concern over arbitrary aggregation of facilities by adding the phrase operationally dependent as well as clarifying that piping connections alone would not extend the 1/4 mile distance restriction.

Pioneer requested that the commission "Please define "directly operationally related" in the rule or preamble. This language is undefined and open to interpretation. Also, how does the rule reconcile this provision with the OGS definition in (b)(3)? If the intent of the provision is for it to only apply all of the requirements of (b)(3) are met first, then there needs to be a clarifying link between this provision and (b)(3). However, a 1/4 mile distance requirement does riot fit the definitions of "contiguous" or "adjacent", Furthermore, only through formal rulemaking could the EPA expand the definition of "contiguous or adjacent" to include a test for interdependency. The interdependency approach for source aggregation is a revision of the PSD and Title V regulations without proper rulemaking and opportunity for public comment, and arguably in violation of the federal Administrative Procedures Act and outside the statutory authority of the Clean Air Act."

The commission concurs with the commenter and has changed the phrase "operationally related" to "operationally dependent." The commission agrees and has changed the rule in response to this and similar comments expressing concern over arbitrary aggregation of facilities by adding the phrase operationally dependent as well as clarifying that piping connections alone would not extend the 1/4 mile distance restriction.

ERM commented that the "TCEQ should consider situations where there is common equipment between a facility/sources authorized or to be authorized by an OGS and a facility/sources authorized by another mechanism such as a PBR or a permit. For example, what if there is a chemical plant authorized by an NSR permit with a fractionation unit authorized by an OGS, where both a chemical processing unit and the fractionation unit vent to the same control device?"

Use of the PBR is limited to one registration per site for operationally dependent facilities. If two facilities with the same owner are not dependent but adjacent the registration for an OGS may be used even if the site is sharing a control device. Where sites are sharing a control device the authorization complexity increases and PBRs should be incorporated into the NSR permit at renewal or amendment of the NSR permit. At that time the OGS will be part of the NSR permit and further authorizations will need to be through the NSR permit.

ETC stated "TCEQ has proposed requirements for the Texas oil and gas industry that are not equitable with other Texas industries. Examples of provisions in the proposed PBR that would unfairly single out the oil and gas industry for discriminatory treatment include the concept of a single PBR authorization for an entire site, which is a requirement that is not currently applied in other industries, e.g., chemical plants and refineries."

The commission respectfully disagrees with this comment and has not changed the language in response. The commission respectfully disagrees that combining requirements for common, dependent facilities is unfair. Previous PBR §106.352 and Standard Exemption 66 as far back in history as 1986 included a number of common, dependent facilities. Many other industry segments (concrete batch plants, rock crushers, material handling, asphalt concrete plants, surface coating, aerospace manufacturing, etc) have also been included in plant-wide or groups of dependent facilities under PBRs or standard permits. This combination of

requirements follows THSC, §382.0511 which empowers the agency to consolidate authorization were deemed appropriate. The groups of dependent oil and gas facilities in close proximity (1/4 mile) under common control on the same property is an appropriate mechanism for authorization and is on a practical basis consistent with thousands PBR registrations accepted currently and allows a comprehensive evaluation of insignificant and protective emissions.

Pioneer and Kinder Morgan commented that, "The requirement of "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" is unclear. Adding the language "30 TAC §105.352" prior to "permit by rule" would help clarify this and allow for other PBRs at the same OGS. For example, a water injection facility, which is listed under the exclusions to §106.352 in (d)(2)of this proposal, could be co-located at the same OGS as facilities permitted by §106.352 that would need to be covered by a different PBR, §106.351."

The commission agrees with this comment and has changed the rule to add "§106.352" prior to "permit by rule" to help clarify the meaning and scope.

Kinder Morgan also stated "Moreover, the phrase "{o}ther 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" is unclear as to whether this is referencing back to 116.111 or you can use other PBRs in conjunction with §106.352. Accordingly, the rule language should be clarified."

The commission agrees with this comment and has changed the rule in response.

The commission agrees with the commenter that the meaning and intent of this sentence is unclear and deleted the last sentence of this subsection as it is redundant with the protectiveness requirements in subsections (b)(6) and (k).

ETC stated "the term "operationally related," used in subsections (a)(1), (b)(5)(A), and (b)(5)(C) of the proposed PBR, and in subsections (a)(1) and (b)(5)(C) of the Standard Permit, should be changed to "operationally dependent." The term "operationally related" is very vague and subject to varying interpretations. Moreover, the use of that term in the PBR and the Standard Permit would result in improperly overbroad groupings of facilities. The term "operationally dependent" is narrower and, as such, would eliminate the overbroad grouping problem that would be created by use of the term "operationally related." Use of the term "operationally dependent" would result in the creation of coherent and sensible groupings for purposes of PBR coverage."

The commission agrees and has changed the rule in response to this and similar comments expressing concern over arbitrary aggregation of facilities by adding the phrase operationally dependent

EDF commented that, "The prohibition of using PBR at a permitted site should be extended to any major source of emissions, not just an operationally related one. The Texas SIP and the Texas Health and Safety Code prohibit the authorization of MSS emissions from major facilities through PBRs. EPA's SIP approval of Texas general PBR provisions clarifies that EPA approved the use of PBRs only for non-major facilities."

The commission has not changed the rule in response to this comment. The commission's intent and revised rule wording clearly states that this PBR may not be used to circumvent federal NSR applicability or requirements.

ConocoPhillips further stated that "regardless of the number of PBRs, the emissions from an oil and gas site be limited to the long standing limits of 25 TPY of SO_2 and VOCs and 250 TPY of CO. Once a project triggers the requirement for a PBR, all facilities that are project affected at the site where the project was undertaken would be included in the PBR. As an incentive to decreasing emissions from the site, we are proposing that if emissions increased by a project are offset below the allowable thresholds by concurrent decreases (validated by adequate recordkeeping) from other facilities at the site to less than the trigger thresholds in (c)(1)(B), the revised PBR should not be triggered so long as the overall emissions thresholds for the PBR of 25 TPY VOC/S02 and 250 TPY NO_X/CO are being met."

The commission has not changed the rule in response to this comment. The commission has numerous examples of inappropriate stacking of Standard Exemptions, PBRs, and standard permits at NSR permitted sites, where the facilities are operationally dependent on each other. The incentives built into the revised PBR include reduced fees and more flexible deadlines for registrations under the lower limits of Level 1 of the PBR. In addition, if new project increases are offset by other decreases at a registered oil and gas operation, the protectiveness review is limited and simplified.

ETC states "the proposed language would add the requirement that, to be included within a single OGS, facilities would have to be operationally dependent on one another. This addition is essential because it prevents overbroad groupings of facilities that, in actual practice, are unrelated, and thus should not be considered to be within the same OGS. Using only the three criteria currently proposed by staff would result in overbroad groupings because none of the three proposed criteria - physical proximity of property, common ownership/control, and common industrial classification - would take into account the particular operational characteristics of the facilities at issue. Adding the concept of operational dependence will prevent the artificial and improper grouping of facilities lacking any real operational connection with one another. (A) Any new facility or new group of operationally related dependent 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. Use of the term "operationally dependent" would result in the creation of coherent and sensible groupings for purposes of PBR coverage."

The commission agrees with the commenter and has changed the phrase "operationally related" to "operationally dependent." The commission emphasizes that aggregation for major source new source preconstruction and federal operating permits review may be required to evaluate different spacing as guidance and rules are promulgated under federal rules, and that the PBR and standard permit do not supersede any of those requirements.

Sierra Club comments the term "operationally related" should be defined.

The commission agrees with the commenter and has changed the phrase "operationally related" to "operationally dependent" for clarity.

TXOGA "is specifically concerned with how TCEQ intends to require that particular facilities must be aggregated into a single OGS authorization. TXOGA requests that TCEQ provide assurances that the requirement will not be used to aggregate facilities into a single PBR or a single Standard Permit if the facilities should not reasonably be aggregated together."

The commission agrees and has changed the rule in response to this and similar comments expressing concern over arbitrary aggregation of facilities by adding the phrase operationally dependent as well as clarifying that piping connections alone would not extend the 1/4 mile distance restriction.

Targa stated "The biggest concerns Targa has with the definition of OGS are with the shifting boundaries of the OG. The focus should be less on the distance between the sites and more on the operational dependence. Targa believes the TCEQ should reevaluate the impact of the proposed OGS definition in (b)(5)(C), which states: "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 great than a 1/4 mile from the facilities associated with the project requiring registration under this section." Under this proposed provision, the boundaries of the OGS and the facilities authorized by the single PBR would shift project by project depending on where the 1/4 mile radius comes to rest. This sets up a real compliance problem as the boundary of the OGS and facilities authorized by the PBR are not fixed. The revised language needs to define an OGS with a fixed boundary. "

MarkWest also "remains concerned about the lack of clarity surrounding the Commissions proposed language to define the area that determines the facilities to be included as a single site for the purpose of determining fugitive emissions under subsection (b)(5)(C). While we appreciate the staffs continued attempts at drafting language that breaks what many people refer to as the "daisy-chain" effect, as currently drafted, the language is still problematic."

The commission agrees and has changed the rule in response to this and similar comments expressing concern over arbitrary aggregation of facilities by adding the phrase operationally dependent as well as clarifying that piping connections alone would not extend the 1/4 mile distance restriction.

Kinder Morgan states "The proposed PBR includes registration requirements for all facilities or groups of facilities at OGS which are directly operationally related to each other and are located no greater than percent mile from the facilities associated with a project. As drafted, the proposal should be clarified to link with (b)(3) so it is clear that this requirement only applies if you meet all the requirements of (b)(3). In addition, the term operationally related should be replaced with operationally dependent. The effect of subsection (b)(5)(C) is to shift the authorization boundaries on a project by project basis and to potentially daisy-chain an entire pipeline system."

The commission agrees and has changed the rule in response to this and similar comments expressing concern over arbitrary aggregation of facilities by adding the phrase operationally dependent as well as clarifying that piping connections

alone would not extend the 1/4 mile distance restriction. The commission has also defined project to be consistent with other NSR permitting actions. The commission has also revised the scope of registration expectations and established a fixed boundary.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that subsection (a)(1) states that this PBR cannot be used at a site with a §116.111 permit, therefore, there does not seem to be a case where certification at a major site would apply. Furthermore the word "new" should be inserted before "major Sources." Delete this requirement if sites authorized under §116.111 cannot use this PBR. For projects at existing major sites, establish emission increases less than any applicable threshold or contemporaneous emission increases for new major sources or major modifications under NNSR or PSD."

EDF commented that, "PBRs should not be allowed at major sites. The TCEQ should explain the need for this section in light of §106.352 (a)(1)."

The commission has not changed the rule in response to this comment. The new PBR is not allowed to be used at major PSD or NNSR sites if the project is related to the major source, but unrelated facilities are allowed to use this PBR, although this scenario is unlikely to occur. However, planned MSS may be authorized under this PBR, even at major NSR sites as long as there are no federal preconstruction applicability issues.

Existing facility

Sierra Club and 2 individuals commented that the "TCEQ should make it clear that any change that increases emissions or requires new construction triggers site-wide applicability of the new rules, not just for the piece of equipment or emission source that was modified."

One individual commented that, "Existing facilities should not be grandfathered and should be made to comply with the proposed regulations. The wells in Denton County emit 37 tons of VOC daily and other hazardous emissions. Allowing them to continue is an injustice."

Five individuals, ABCA, and Earthworks Texas Oil and Gas Accountability Project stated "the rule should apply retroactively in order to avoid delays of needed upgrades to facilities. The rule should apply to all equipment at all sites, absent some undue hardship to the owner or operator" and "should apply retroactively to the extent feasible. At the ABCA, we are most concerned that the new rule will cause delays of needed upgrades and maintenance as a means of avoiding application of more stringent standards. The only way to avoid this outcome is by applying the new rule to all equipment at all sites, absent some undue hardship on the operator. Equal treatment of all applicable equipment and operators will ensure the rule does not have the unintended consequence of making air quality worse in Texas."

The commission has not changed the rule in response to this comment. The permitting requirements and applicability of any PBR is specified in the TCAA to occur only when a new facility is constructed or changed in such a way as to increase previously authorized emissions.

Nortex commented that, "Sierra Club's recommendation that existing facilities be deprived of their current PBRs even if no change is made would have the effect of upending decades of agency rule and policy on the validity of PBRs, and would impose a requirement that goes far beyond federal NSR-on sources which by law are required to be both minor and insignificant."

The commission agrees with this comment and has not changed the rule to require existing, unchanging facilities to meet all requirements of the revised rule.

TRAED and 5 individuals stated that "all old OGS should not be grandfathered in to the proposed changes in the permit by rule process. This will just encourage developers to place as many pieces of equipment on an already existing site with no regard to the surrounding communities or people living next to the existing sites."

The Old Town Neighborhood Association recommended that the commission "not allow grandfathering of existing permits due to future plans to add wells based on the price of natural gas."

The commission has not changed the rule in response to this comment. While the TCAA does not allow the commission to arbitrarily require unchanged existing authorized facilities to obtain a new authorization, any operator which adds pieces of equipment to an established site after the effective date of the revised PBR will be required to meet the new requirements for the newly installed facilities. Any residences in close proximity will be considered during the protectiveness review, which includes both new and existing facilities.

Representative Lon Burnam stated "there are too many grandfathered facilities. The new rule should apply to all facilities in a nonattainment area on the same date as the MSS provisions on January 5, 2012. Exempting the vast amount of facilities already in operation in Fort Worth renders the new rule virtually ineffective for his constituents and many others living on the Barnett Shale. Representative Burnam opposes indefinite PBR authorization and proposes that PBRs be renewed every three to 5 years to incorporate new control and process technology."

The City of Fort Worth commented that "requiring renewal of permits would allow the TCEQ and communities to learn from new ongoing research and to adapt to the development of more effective control technologies. The City of Fort Worth also commented that "five-year PBR renewals and three-year standard permit renewals should be required to take advantage of the advances in scientific/engineering information, federal regulatory changes, and improved emission control technologies." The City of Fort Worth also commented that "the foreseeable growth in population density in the Barnett Shale region should trigger a review of the nearest receptor and the applicable control requirements, since a once rural OGS could become a suburban site in a 3 to 5-year time frame."

Senator Wendy Davis recommended that, "The permit by rule should include an appropriate renewal registration cycle."

The Sierra Club stated "all existing OGS should register under the new PBR or standard permit with 5 years, 2 years for nonattainment areas. The PBR should require re-registration every 5 years to keep TCEQ current on the number of OGS within the state and to update changing requirements of the PBR. The proposal could require a phased approach for all existing sites to seek authorization under the proposed permits within 5 years, beginning with those sites located in nonattainment areas."

Mayor Calvin Tillman of DISH commented "The rule should include the reevaluation of existing facilities to make sure they qualify for the new permit by rule."

One-hundred thirty-four individuals stated "all existing OGS should register under the new PBR or standard permit with 5 years, 2 years for nonattainment areas. The PBR should require re-registration every 5 years to keep TCEQ current on the number of OGS within the state and to update changing requirements of the PBR.

TRAED, 5 individuals, ABCA, and Earthworks Texas Oil and Gas Accountability Project recommended that the TCEQ should require periodic permit renewals and clearly delineate what acts lead to permit revocation or denial. Other segments of society, activities, and trades where government has issued authorization are of limited duration."

Senator Wendy Davis stated that "because TCEQ has waited so long to revise these rules, the agency should create a grant-based incentive program for companies to retrofit existing facilities to ensure their level of compliance equals that of new facilities."

The commission has not changed the rule in response to this comment. The requirements of any historical Standard Exemption or PBR remain in effect until new facilities or other changes occur which requires updating a claim,

registration, or certification. The commission does not have compelling evidence to add a requirement for renewal on this industry, and such a requirement would place an undue burden on a specific industry segment disproportionately to other industries. For facilities in nonattainment areas, 30 TAC Chapters 115 and 117 are the appropriate mechanism to require additional controls beyond those of any PBR, standard permit, or permit. At this time the commission does not have access to discretionary funding to sponsor a grant program to encourage control upgrades on existing, unchanged facilities.

Pioneer and Kinder Morgan comment that "it should be clarified if existing facilities can keep their PBR status under a historical PBR even if other facilities at the same OGS are changed and subject to the new PBR outlined in this proposal, as long as they are not operationally related to the facilities applying for the new PBR. If so, the language should be clarified to state that existing facilities at an OGS shall maintain their current authorization under the historic PBR that was claimed at the time of construction or change of the facility, regardless of whether the facility was registered. And Pioneer states further, as elaborated on in my comment for (a)(1) above, if an existing facility is changed at an OGS, would the whole site now be only under the new §106.352? How would the non-changed facilities (if they are versus if they are not operationally-related) under previous authorizations, or registrations, be distinguished? Please provide clarification on this issue in the rule or preamble."

The commission agrees with this comment and has clarified various rule language to emphasize that (except for planned MSS and consideration for impacts evaluations in close proximity to new projects) all existing, unchanged facilities

retain their historical Standard Exemption or PBR authorization, even if never registered.

Kinder Morgan commented that, "The proposed PBR should clarify that new PBR requirements should only apply to new facilities or modified facilities where the changes result in an emissions increase. Applicability should not be triggered under the new PBR for changes that result in same or decreased emissions levels. The rule as currently drafted includes within the scope of covered facilities those that reduce the quantity of their emissions. The effect of the current language contradicts the preamble which states registration is triggered when existing facilities' PTE are increasing. The proposed language would result in a disincentive for reducing emissions at an OGS."

The commission agrees with this comment and has clarified various rule language in response. The new PBR specifies the limited circumstances of applicability in the definition of "project." The actions which trigger the new PBR requirements are new facilities or changes to existing facilities which increase the potential to emit over previously certified emission limits only.

TPA commented that, "There has been no science-based demonstration justifying the application of current standards retroactively to existing sources. There has been no air quality study that supports this outcome and no demonstration that public health is being adversely impacted as a result of the production-related activity in the Barnett Shale area or any other area in Texas. Controls and demonstrations for the sake of such are not supported under the federal or Texas Clean Air Acts. Regulated entities are not required to make demonstrations or add controls for the sake of such; instead a cost-benefit analysis is performed in terms of cost per ton of pollutant reduced. The TCEQ has not conducted that analysis. Moreover, if the TCEQ had conducted the review required for major environmental rules, as discussed earlier, all or some of this analysis would have been developed. In that case, the agency, the regulated community and the public would be better informed of the need and basis for many of the provisions of this proposed PBR. Without such an analysis this rule lacks a reasoned justification or rational basis for its promulgation."

The commission respectfully disagrees with this comment. The evaluation performed by the commission has shown that certain amounts of various air contaminants may not be able to demonstrate protectiveness using generally accepted techniques (emission calculation methods, dispersion modeling, etc). Specific and extensive details of the emission impact analysis are provided in both the section by section discussion of this document as well as the standard permit for oil and gas production facilities background document.

Senator Davis also recommended "the definition of receptor be expanded to more accurately reflect the group to be protected and should include places where people spend a significant amount of time or a significant number of people congregate. The definition should also include places such as schools, office buildings, hospitals, day-care centers, community centers, restaurants, stores, hotels, and playgrounds. She cited a Fort Worth City Ordinance adopted in 2009 which would include these places under defined terms such as "habitable structure," "public building," and "protected use."

Representative Lon Burnam stated that the definition of receptor should not exclude "places were people spend significant amounts of of time and thus may be exposed to emissions from near-by drilling and associated operations." He further stated that "because emission limits under the rule will, in many cases, be determined by the distance to the nearest receptor under the protectiveness review, it's extremely important that the definition include all places where people spend enough time to be impacted by exposure to drilling-related emissions." He recommends changing the definition of receptor to include any building which is in use as a single or multi-family residence, school, businesses and other places where people are present for more than three hours per day, or place of worship at the time this section is registered.

The Sierra Club and 134 individuals stated the definition of receptor should be any building or public place where people are present three hours per week (consistent with NSR and other standard permits). The definition should include hospitals and public parks. The Sierra Club additionally commented that the current receptor definition excludes such places as hospitals and public parks. We recommend broadening the definition, consistent with NSR and other standard permits, to include any building or public place where people are located at least three hours per week. In addition to residential homes, the receptor definition should include workplaces and public areas. Individuals who work 8 or more hours per day adjacent to an OGS are entitled to the same safety protection as residences.

TRAED and 5 individuals commented that, "Receptor should be defined to include hospitals, out-patient care facilities, day-care facilities, early childhood centers, retirement homes and retirement communities."

Five individuals, ABCA, and Earthworks Texas Oil and Gas Accountability Project commented that, "Receptor should include the functional equivalent of schools, multi-family residences, long-term care facilities, day-care facilities, early childhood centers, retirement homes and retirement communities. If the definition is to be consistent with the air quality standard permit for rock crushers, as stated in the comment summary from the April 8, 2010 stakeholder meeting, then it should be consistent with the supporting code for that permit found in THSC, §382.052. This statute requires any concrete crushing facility to be located at least 440 yards from a school and that facilities constructed or modified within 3000 feet of a school be evaluated for short and long-term health effects.

ABCA additionally commented, "Minimum distance requirements protect the people living in unincorporated parts of a county. As stated above, there is evidence that the legislature established 440 feet as a minimum setback requirement to protect schools from industrial air contamination. Many municipalities have adopted setbacks of 500 feet or greater to protect their populations. While it is fortunate for those people living in cities to have the protection, the result is that industry has moved into unincorporated parts of a county in order to avoid more stringent municipal setbacks. As such, some of the largest and most polluting OGS, often with multiple permits granted by the old PBR, are located next to residences and schools in unincorporated areas. For the many people living in these areas, the rules TCEQ issues are their only protection. Fifty feet is simply not enough to protect a family living next an OGS containing 15, 20, or 40 pieces of industrial gas production equipment ... .By including functional equivalents in its definition, "receptor" will effectively protect sensitive populations such as children, the ill, and the elderly. There is ample evidence that sensitive populations are more likely to be harmed by air emissions than the general adult population. The current definition of "receptor", however, is not clear enough in protecting these populations."

EDF recommended the definition of receptor should be modified to include all such places in order to ensure the maximum degree of public health protection. Specific places that should be included in the definition of receptor include medical facilities (hospitals, health care facilities, etc.); nursing homes; places of business (offices, stores and other workplaces and commercial establishments); hotels/motels; and parks; among others.

One individual recommended that the commission "modify the proposed PBR and Standard Permit to provide greater protection for surrounding populations. . .broadening the definition, consistent with NSR and other standard permits, to include any building or public place where people are located at least three hours per week. In addition to residential homes, the receptor definition should include workplaces and public areas. Individuals who work eight or more hours per day adjacent to an OGS are entitled to the same safety protection as residences."

The commission partially agrees with this comment and has revised the rule to include day-care centers and hospitals. This definition establishes a threshold for ensuring that an evaluation is completed for the most sensitive populations and those residing in permanent dwellings close to an oil and gas facility, the commission has not included retirement homes or communities since they are already covered by "residence." Further, the commission has expanded the definition of receptor to include certain businesses. These receptors are included if they are occupied regularly as those in the general public who occupy these

structures may be exposed for extended periods of time. The business definition however excludes those businesses whose primary function is oil and gas production, as the emissions they are exposed to are the same - and in much higher concentrations - as the site seeking authorization may be emitting. The commission respectfully disagrees that the definition of receptor should be expanded to include all possible structures which may be occupied at some time for limited durations. The commission also notes that as required in §106.352(a)(1), if there is a local ordinance or regulation which is more stringent than the requirements of this PBR, the facility must comply with that more restrictive standard.

NorTex "disagrees strongly with the proposals offered at the public meeting to expand the definition of receptor to all workplaces or "structures occupied for more than three hours per week." This proposal is completely inconsistent with the manner in which receptors have been handled previously in air permitting. Making this significant change is agency policy via a single PBR, which by definition, has negligible impacts, would be highly inappropriate and would impact small and large businesses in ways that could not be foreseen absent full, public consideration."

The commission partially agrees with the comment and is not changing the language of this subsection to include any structure which is occupied for short durations (3 hours per week).

The City of Fort Worth commented "the definition of receptor should be expanded to include the nearest civilian-occupied structure to the O&G facility (i.e. that nearest structure which is not owned or occupied by the person or company that exercises day-to-day control over the operations of the site)."

The commission partially agrees with this comment and has revised the rule to include day-care centers, hospitals, and certain businesses. The commission respectfully disagrees that the definition of receptor should be expanded to include all possible structures which may be occupied at some time for limited durations. This definition establishes a threshold for ensuring that an evaluation is completed for the most sensitive populations and those residing in permanent dwellings or for extended periods of time close to an oil and gas facility.

Planned MSS

EPA commented that "§116.620(b)(5)(E) and §106.352(b)(5)(E) allows for MSS emissions to be authorized without registration. MSS emissions from OGS must be authorized by January 5, 2012. If an OGS elects to authorize MSS before January 5, 2012, what mechanism will be used to amend the standard permit or PBR registration? What is the regulatory basis for not including these emissions before January 5, 2012? What mechanism will TCEQ use to ensure that all existing OGS facilities, permitted under the current standard permit and PBR, have MSS emissions authorized by January 5, 2012 if they are not required to register them when claiming only the MSS portion of the proposed standard permit and PBR?"

The commission has not changed the rule in response to this comment. The rule requires planned MSS emissions to be quantified and meet applicable limits by

January 5, 2012, and also requires certain records to be maintained. It is not necessary for sites already registered or claiming an unregistered Standard Exemption or PBR to revise their authorization. Facilities or groups of facilities that claim a historical Standard Exemption or PBR only need to have compliance information available and only need to submit paperwork the next time a change is made at the site requiring a registration. Sites that have certified emission limits may submit, free of charge, a Form APD-CERT to change the certified limits to include MSS emissions. The regulatory basis for the deadline of January 5, 2012 is established in §101.222(h). The commission has considered the mechanism for sites that are only authorizing MSS emissions, but not submitting an actual MSS registration until the next permitting action (PBR revision) after January 5, 2012. This is consistent with our unregistered PBR authorizations which have to meet all the PBR requirements but do not have to submit any paperwork. All OGS are required to have appropriate MSS records and be able to demonstrate to agency enforcement that MSS emissions meet the protectiveness limits of the PBR. The next time the site PBR needs to be revised, the MSS emissions will be included in the registration. This requirement is for administrative scheduling purposes to prevent all the thousands of unregistered and registered oil and gas PBR sites submitting paperwork at the same time. The Regions will ask for documentation on inspections and site visits to demonstrate compliance.

TXOGA states that "MSS emissions that have already been authorized under §106.352 should not be required to be reauthorized. Some of the authorized MSS emissions have already demonstrated compliance with health impacts analysis. TCEQ cannot simply invalidate all previously authorized MSS emissions under §106.352. Every single OGS has maintenance emissions and this would require reauthorization for every single OGS. Furthermore, TCEQ authorized maintenance emissions prior to the mandated inclusion date for other industries and has not revoked those previously authorized MSS emissions after the mandatory inclusion date.

TXOGA commented that some locations (under NSR permit) have already authorized maintenance emissions and met the current §106.352. These sites should not have to undergo impacts review."

El Paso commented that, "The exclusion of subsection (b)(6)(B) from subsection (b)(5)(B) will allow existing facilities that meet the current PBR limits to continue to operate without having to make physical or operational upgrades. Alternatively, if TCEQ has since determined that planned MSS activities are not authorized by the current version of §106.352, El Paso suggests the following revision to §106.352(b)(6)(B): existing authorized facilities, or group of facilities, at an OGS must meet only subsection (i) of this section except previously authorized MSS emissions."

The commission has not changed the rule in response to this comment. The rule requires planned MSS emissions to be quantified and meet applicable limits by January 5, 2012, and also requires certain records to be maintained. It is not necessary for sites already registered to revise their permit. Sites that are registered only need to have this information available and only need to submit paperwork the next time a change is made at the site requiring a permit revision.

Sites that have set up certified emission limits may submit, free of charge, a Form APD-CERT to change the certified limits to include MSS emissions.

In order to establish what the applicable limits are for MSS emissions, a protectiveness review must be performed. The applicable limit could be the cap of the authorization level or a more stringent limit based on the protectiveness review. It is also important to note that the protectiveness review for MSS emissions must include any other emitting sources during the MSS events. For example, if there are oil tanks at the site, which are continuously emitting, those emissions will be included in the evaluation; however, emissions from loading of the tanks, which are not continuous and do not occur at the same time as the MSS events, will not be included.

Although some companies have registered MSS emissions, these MSS requirements apply to all sites, regardless of whether registration has already occurred. Hourly limits were not in place prior to this rule, which means that short-term emission levels have been registered that are very high and potentially could cause a detriment to public health and welfare.

Currently, only a small percentage of sites have registered any MSS emissions. A survey of recently issued PBRs showed multiple cases of high estimated short-term MSS emissions from 63 lb/hr to 2,914 lb/hr. Some of the recently issued examples are: 1) PBR registration no. 53476 (project no. 152342, site located in TCEQ Region

1 - Amarillo) and PBR registration no. 80325 (project no. 125687, site located in TCEQ Region 1 - Amarillo) both authorized 2,914 lb/hr of VOC emissions from tanks during periods when the tanks VRU is inoperable; 2) PBR registration no. 72355 (project no. 144380, site located in TCEQ Region 7 - Midland) authorized 311 lb/hr of VOC blow down emissions from gas gathering system depressurizing; 3) PBR registration no. 56689 (project no. 149188, site located in TCEQ Region 1 - Amarillo) authorized199 lb/hr of VOC emissions from 48 compressor blow downs per year; 4) PBR registration no. 88193 (project no. 146483, site located in TCEQ Region 1 - Amarillo) authorized 194 lb/hr of VOC emissions from two compressor blow downs per month; 5) PBR registration no. 89735 (project no. 149267, site located in TCEQ Region 1 - Amarillo) authorized 185 lb/hr of VOC emissions from 48 compressor blow downs per year; 6) PBR registration no. 90651 (project no. 150796, site located in TCEQ Region 5 - Tyler) authorized 90 lb/hr of VOC emissions from 24 compressor blow downs per year; 7) PBR registration no. 50556 (project no.160267, site located in TCEQ Region 11 - Austin) authorized 180 lb/hr of VOC emissions from pipeline and tank degassing in addition to 65 lb/hr of VOC emissions from 40 compressor blow downs per year; 8) PBR registration no. 93527 (project no. 160089, site located in TCEQ Region 7 - Midland) authorized 1,062 lb/hr of VOC emissions from 12 compressor blow downs per year, quarterly flare maintenance, and biannual vessel maintenance; 9) PBR registration no. 93178 (project no. 159331, site located in TCEQ Region 10 - Beaumont) authorized 690 lb/hr of VOC emissions from flared tank and compressor emissions during VRU downtime for maintenance; 10) PBR registration no. 92354 (project 156947, site located in TCEQ Region 7 - Midland) authorized 63 lb/hr of VOC emissions

from venting during flare and vessel (separator and heater treater) maintenance; 11) PBR registration no. 26039 (project no. 159364, site located in TCEQ Region 12 - Houston) authorized 681 lb/hr of CO emissions from 96 startups and 96 shutdowns associated with two turbines; 12) PBR registration no. 44878 (project no. 160163, site located in TCEQ Region 15 - Harlingen) authorized 310 lb/hr of VOC emissions from two MSS blow downs. It is highly likely that there are more sites with unregistered similarly high MSS emissions. It should be noted that these MSS emissions occur for a small percentage of the total site operating time. Although, an MSS event may only occur 60 hours out of a year, the emissions still need to be protective for those 60 hours.

It is important for all sites to assess their MSS emissions. This assessment includes: 1) taking into account all planned MSS activities which result in significant emissions; 2) determining a realistic estimate of emissions; and 3) demonstrating that the emission rates are protective. If protectiveness cannot be demonstrated, options to consider are changing the way the MSS activity is done or adding a control/recovery device. Because most PBRs did not previously have hourly limits or a protectiveness review, there has been no determination by the agency and no demonstration by applicants that represented short-term MSS emissions are protective. This means that there is uncertainty as to whether the high short-term emissions authorized by the agency are protective. They could be protective for a site in a remote location with no receptors nearby, but a protectiveness review needs to be done as demonstration. The protectiveness evaluation takes into account how close the emission point is to a receptor and

how high above ground the emission release point is. In order to ensure protectiveness of public health and welfare the commission has determined all sites, with or without previously registered MSS emissions, are subject to the MSS requirements of this rule.

TAEP commented that, "Planned MSS must have clarity in the definition of source and the estimating methodology."

Encana commented that, "The provisions addressing MSS activities represent a new class of emission sources subject to great variability. The TCEQ and the industry could benefit from an integration of a TCEQ/Industry working group to work out the details regarding MSS sources, calculations, and compliance with protectiveness review and NAAQs (sic NAAQS) compliance demonstration. Encana would be willing to participate in this workgroup."

The commission is building MSS estimation methods into the emission calculations spreadsheet being developed with feedback from stakeholders. The preliminary draft of this spreadsheet is available at *http://www.tceq.state.tx.us/permitting/air/nav/nsr_news.html*. In addition, the agency will be providing outreach and sponsor a workgroup to work on various issues. We appreciate Encana's willingness to volunteer.

El Paso commented that, "§106.352(i) applies to any facilities using the section or previous versions of this section to comply with certain requirements which will, in fact, require these facilities to physically or operationally upgrade. For example, proposed §106.352(1)(4)(C) will require 98 percent control efficiency for VOX and H_2S emissions during compressor startup, regardless of the level of these emissions. This will require installation of controls. Per TCEQ's September 25, 2006 guidance, *Planned Maintenance, Startup and Shutdown Emissions* are authorized by the current version of §106.352, provided that the nearest receptor is at least 1,200 feet away."

The commission did not change rule language in response to this comment. Previously applicable PBR rules at OGS (i.e. PBRs §106.352 and §106.512, and associated previous PBR and Standard Exemption versions) did not adequately ensure protectiveness for MSS emissions; impacts reviews for rulemaking of the previously applicable rules did not include impacts reviews for MSS emissions and did not include short-term (i.e., lb/hr) emissions impacts reviews. In previous PBR registration reviews, the commission has seen uncontrolled MSS emission rates of several hundred lb/hr or more of VOCs and has seen MSS emissions rates of 1,000 or more lb/hr of VOCs before controls. Based on the impacts reviews for the new OGS PBR, the commission believes that allowing authorization of OGS MSS emissions retroactively will not ensure protectiveness. Therefore, the commission determined that MSS emissions could not really be authorized in previously applicable PBR rules and that MSS emissions were not really authorizable under PBRs until these new OGS rules became effective. The commission agrees that to pass impacts review under the new OGS PBR, MSS emissions may need to be controlled or facilities may need to be upgraded.

Although OGS MSS under PBRs was addressed by companies in registration submittals and reviewed by the commission, the commission has determined that based on all the information available to the commission, protectiveness may not have been adequately addressed.

El Paso suggests that "TCEQ should establish a *de minimis* emission level below which any MSS activity is exempt from proposed §106.352(i), particularly for existing facilities."

The agency has not established a *de minimis* emission level for exempting MSS emissions from being subject to §106.352(i). Instead the rule lists the type of MSS activities that are anticipated to result in quantifiable hourly emissions and expects that emissions associated with these types be estimated. Other MSS activities which are not expected to have contributing emissions are stated in the rule and emissions are not required to be estimated; only recordkeeping requirements are applicable.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Many times a specific MSS activity listed in the 116 permit maintains its PBR authorization by reference. Another example: An engine related MSS activity might be authorized through a case-by-case permit, while on-site field header or separator blow down needs to be authorized through a PBR. It is critical to industry to continue allowing PBR authorizations for MSS activities as they are identified provided compliance with the rules can be demonstrated and the authorizations are rolled in to the 116 permit at next permit renewal or modification as required in the current rules. Even though current rules prohibit using PBRs to circumvent Title V requirements, the agency can restate the requirement in the text of §106.352(i)(2)(C) to roll in all PBR authorizations at next permit revision if there is a concern about this type of circumvention."

The commission has not revised the rule in response to this comment. This PBR is designed to address all the MSS associated with oil and gas processes at a simple OGS with insignificant overall emissions. Where an OGS has a case-by-case NSR permit with MSS addressed for the oil and gas process the situation can be complex and this PBR should not be applied. Where MSS is not addressed in the case by case NSR permit the MSS for the site can be addressed with this PBR. Where an OGS has a case-by-case NSR permit with MSS addressed the operator may be able to use other PBRs just not this PBR.

Sierra Club commented that, "The PBR allows major sources to receive coverage of Maintenance, Startups, and Shutdowns (MSS) under the PBR. This exception must be eliminated. EPA has explicitly commented that MSS may only be addressed through new source permit processes; a separate MSS-only permit essentially allows a major facility to evade NSR requirements. Excess emissions during MSS are violations of the applicable emission limits and may aggravate air quality and interfere with maintenance of the NAAQS. This is particularly true in Dallas-Fort Worth. Therefore, major sources should not be allowed to seek authorization for excess emissions under the PBR."

The commission respectfully disagrees with this comment. The commission has

not revised the rule in response to this comment. Planned MSS may be authorized under this PBR, even at major NSR sites as long as there are no federal preconstruction applicability issues.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested clarification regarding "What to do about sites that had previous MSS but do not pass the proposed criteria or able to model protectiveness? What modeling criteria should be in place for MSS emissions (very short duration and sporadic). Modeling for consistent lb/hr short-term impact does not seem appropriate for MSS emissions unless true dispersion characteristics are taken into account. Need to better understand the proposal, strategy recommendations, and impact." The commentors provided additional detailed physical and operational information describing high pressure blowdowns.

The commission has changed the rule in response to this comment. The sporadic short-term MSS emission limits and protectiveness tables have been revised to include the situations where high pressure lines and systems are vented based on a detailed analysis of information provided by industry. Subsections (g)(3) and (h)(3) have been updated to include limits and subsection (m), Table (4), updated for additional dispersion information for releases greater than 30 psig (details in the SECTION BY SECTION ANALYSIS).

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "§106.263(b)(6)(C) specifically excludes the use with §106.352. It would be clear if you pulled the requirements into the rule from §106.263(e)."

The commission partially agrees with this comment and has determined that references to §106.263 are not necessary as control expectations are covered sufficiently by subsection (e)(8) - (13).

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested the commission to "Consider striking this language from the rule based on the extremely low vapor pressure of amines (and glycol) and the associated insignificant emissions. These are water soluble, have low vapor pressures, and insignificant emissions. MDEA, DEA, & DGA vapor pressure is less than 0.01 mm Hg at 68 degrees F, which is less than 0.0002 psia. TEG vapor pressure is listed as less than 0.1 mm Hg at 68 degrees F, which is less than 0.002 psia. Amine/glycol loss is mostly attributed to carryover from contactor within the process (process loss within the pipe, NOT evaporative emission loss in the storage of the chemicals on site). Fluids with vapor pressure less than 1.5 psia OR storage tanks less than 1,000 gallons should be exempt from emissions quantification or recordkeeping, which is consistent with the exemptions set forth in 30 TAC §115.112(a)(1)."

Devon commented on subsection (i)(2)(F) and (3)(A). "The proposed emissions quantification and/or recordkeeping activities associated with amine and glycol chemical replacement and filter changes should be removed from the MSS list due to the *de minimis* emissions associated with these chemicals. Amines and glycols have very low vapor pressures, are water soluble, and remain atmospherically stable at ambient conditions. Losses of amine and glycol over time are mostly attributed to process loss (not environmental loss) due to carryover of amine/glycol with the gas stream through the contactor outlet."

The commission partially agrees with this comment. The commission has further evaluated the potential for emissions from replacing amine and other treatment chemicals and does not believe there is sufficient emission potential to warrant accounting of this activity for a PBR. The agency is not comfortable adding an exemption for heavier oils or smaller vessels for MSS because liquid heals and clingage in vessels can represent significant emissions if forced into the atmosphere for clearing or cleaning purposes.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested to "Strike §106.352(1)(2)(F) from final rule on the grounds of the insignificant emissions associated with amine and glycols. Amine and glycols have very low vapor pressures, are water soluble, and remain atmospherically stable at ambient temperatures. Losses of amine and glycol over time are mostly attributed to process loss (not environmental loss) due to carryover of amine/glycol with the gas stream through the contactor outlet. Furthermore, liquids with a vapor pressure less than 1.5 psia or liquids contained in a storage tank less than 1,000 gallons shall be exempt from emissions quantification and recordkeeping requirements."

The commission partially agrees with this comment. The commission has further evaluated the potential for emissions from replacing amine and other treatment chemicals and does not believe there is sufficient emission potential to warrant

accounting of this activity for a PBR. The agency is not comfortable adding an exemption for heavier oils or smaller vessels for MSS because liquid heals and clingage in vessels can represent significant emissions if forced into the atmosphere for clearing or cleaning purposes.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko recommended to "remove the list in (3) and have discussions centered not needing documentation for activities that result in negligible (if any) emissions released to the environment. We propose "small emission changes that do not need authorization" be defined emissions that do not exceed the protective review limits in place and do not exceed the limits in §106.352(c)(1)(B), (B)(i) - (ii)."

The commission has not changed the rule in response to this comment. The agency has not established a *de minimis* emission level for exempting MSS emissions from being subject to §106.352(i). Instead the rule lists the type of MSS activities that are anticipated to result in emissions, and others which have insubstantial emissions with only recordkeeping of activity. If the commenter's recommendation was accepted, even the smallest activity would require an emission calculation to compare against a value defined as the "small emission change." The approach by the commission instead does not require this unnecessary quantification and check, and instead will rely on likely existing records kept at each location which shows the facilities are kept in good working order.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "If emissions quantification is not necessary for §106.352(i)(3), then recordkeeping for these activities should not be required and is burdensome with no environmental benefit. Existing company job plans or work order systems should suffice for any recordkeeping, and should continue to be maintained as part of operational records and not duplicated for environmental records. If the records are required for environmental reasons as determined by the TCEQ or industry, the retention time on those records should not exceed 2 years. A more inclusive list of recordkeeping documentation should be allowed, including purchase records of replacements and logbooks. The recordkeeping requirements appear to align with large chemical plant recordkeeping versus remote dispersed OGS. We propose "small emission changes that do not need authorization" be defined emissions that do not exceed the protective review limits in place and do not exceed the limits in §106.352(c)(1)(B), (B)(i) - (ii)."

The commission agrees with this comment and has revised rule language to allow any documentation that is currently being maintained that provides the same information will be acceptable. However the commission has determined that maintenance records are necessary and will rely on likely existing records kept at each location which shows the facilities are kept in good working order.

Encana seeks clarification on "what the compliance or environmental benefit of subsection (i)(3) compared to the burden and cost on industry. There is ambiguity in what level of maintenance requires further action, As a result, TCEQ inspectors may be faced with enforcing a subjective standard."

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested additional clarification "to insure that only events with emissions are included."

The commission has not change the rule in response to this comment. The permit holder conducts these important functions in order to maintain equipment at best operating conditions is of interest to the commission, because best operating conditions equals efficient operating which translates to the best conditions for the environment. The commission staff in field operations reviewed typical records currently provided by industry and found that operators already have some form of record that each of the activities took place, including purchase receipts to work orders, to some form of work diary or log. It is our opinion that keeping these records is sufficient to demonstrate compliance with these activities (that they took place) and they are not burdensome.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko recommended changes to subsection (i), including "Blow down and associated emissions relating to Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance, or other activity that meets small emission changes that do not need authorization."

The commission has not change the rule in response to this comment. The commission is including engine blowdowns in §106.352(i)(2) as MSS activities that

are required to have emissions quantified. The commission reserves the authority over any activity that results in emissions, but has only required record of the activity occurring which fall in the negligible category to be recorded, not a quantification.

EPA commented that, "§116.620(i)(4) and §106.352(i)(4) states that engine/compressor startups associated with preventative system shutdown activities can be authorized as part of typical operation for an OGS if certain conditions are met. How would this affect the monitoring, recordkeeping, and reporting (MRR)? Would it be clear from the permit authorization if the MSS from these activities are included in the typical operations? Please provide an explanation of how this provision fits within the context of a standard permit or PBR versus a case-by-case permit subject to public notice."

The commission has not changed the rule in response to this comment. As required in subsection (f), certain operations which rely on controls to minimize emission must be certified, and thus detailed in emission estimates as a part of a registration/certification. This subsection is also not subject to NSR permitting as it is a specific operational scenario and standardized. The control requirements under §106.352(i)(4) were prescribed to ensure protectiveness for a particular operating scenario that the commission was made aware of. The controls were needed for the particular operating scenario due to the scope and magnitude of the scenario and due to OGS industry insistence that the scenario is absolutely necessary for operation of OGS.

TXOGA proposed a change to subsection (i)(4) that would read, "Engine/compressor preventative system activities have the option to be authorized as part of typical operations for an OGS."

The commission has not changed the rule in response to this comment. The only specific scenario presented for consideration for the optional exception was based on the specifics of that scenario as proposed. No additional specific emissions, control, and dispersion characteristics have been reviewed and determined to be acceptable.

El Paso commented that the TCEQ "should recognize that the blowdown to atmosphere of gas from a compressor and compressor engine prior to routine periodic maintenance is the safest way to perform this task. Blowdown of this gas to a control device is both mechanically infeasible and unsafe."

The commission has not changed the rule in response to this comment. The commission respectfully disagrees with this commenter for all circumstances. In some cases, based on the specific equipment, materials, and locations, the option in subsection (i)(4) may not be safe or feasible. In other cases, however, existing plants use this exact method of operation to minimize routine activities and emission releases.

Exterran recommended that subsection (i)(4), "Allow the PBR and the Standard Permit to authorize startup emissions where the owner/operator "minimizes the engine's time spent at idle during startup and minimize the engine's startup time.""

The commission did not change rule language in response to this comment. As discussed in the background document for standard permits (which is also applicable to the PBR rule where overlap exists as in this case), subsection (i)(4) is for "a very specific circumstance the commission has reviewed." The language in subsection (i)(4) is not referring to MSS combustion emissions from engines, and engines themselves, including minimization of startup times, were not the primary reason for subsection (i)(4). MSS emissions for combustion units, including engines, are addressed in the background document as follows: "Emissions from planned MSS due to shutdown and startup of combustion units should not result in any quantifiable hourly emissions change from standard operation of the combustion units with regard to emissions of CO or NO_X. Although there may be transitional and incidental spikes before units stabilize during startups (5 - 15 minutes), overall products of combustion are expected to be within hourly range limits for normal loads during production operations. There are no reasonable controls to be applied during startup and shutdown of combustion units so BACT is to minimize the number and duration of startups and shutdown." Additionally, in response to this comment, engine combustion MSS is not compressor blowdowns MSS. Based on the above, MSS emissions due to combustion in combustion units are sufficiently addressed in the background document and do

not need to be addressed further with the addition of associated rule language. Minimization of startup time for combustion units is not required under the PBR OGS rule. However, the commission does agree that startup time for combustion units should be minimized and believes that doing anything other than minimization of startup time is not in OGS best interest. Minimization of startup time for combustion units under the OGS standard permit is BACT and is required. At this time, issues with minimization of startup time for combustion units with be addressed by the TCEQ Regional Director on an as-needed basis.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "There is nowhere to divert gas or liquid to when a smaller engine is shutdown due to low pressure or high liquid alarms in the separator or well bore. The compressor is shutdown to prevent equipment failure and compounding the issue. The shutdown results in combustion emissions actually being reduced due to lack of running the engine. The pressure in the separator (or well bore) will likely continue to rise over time until there is enough sustaining pressure and flow for the engine to be turned back on. Occasionally wells in the field begin to load up with liquid and reduce the flow rate or potential pressure in the separator (or well bore) and the wells will need to be worked over or plunger lifts added to remove the liquid cap and restore flow rates and pressure. Preventative shutdowns need to be allowed and emissions accounted for, as well as considered as part of typical operations. Large compressor sites might have the capability of divert or load balance gas streams, but smaller engines do not have this capability by design."

The commission did not change rule language in response to this comment. The

commission recognizes that not all oil and gas facilities may be able to use subsection (i)(4) to control emissions, which is why it is an option and not a requirement.

Encana commented on Table 8 located in PBR §106.352 and Standard Permit - Category - Equipment Specifications "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, Encana Response: This requirement is extremely burdensome to operators and should be reserved for the highest emitting facilities, Encana asserts this requirement should be only be required for facilities that emit greater than 80 percent of 40 CFR Part 70 Major Source thresholds."

The commission did not change rule language in response to this comment. The commission has tried to better clarify appropriate records for planned MSS activities being permitted. Where vessels are to be depressured and cleared for maintenance, substantial emissions can be forced into the air depending on the approach used by the operator. The commission has not limited the frequency or dictated control for the PBR. We are simply requiring an accounting with a protective emission limitation. The only way to estimate the emission for the registration is with the information noted. With a set maintenance procedure the volumes and pressures should be a simple check box effort when conducting the

maintenance.

Scope of Registration and Project

TPA commented that, "As currently structured, the geographic boundary of the applicable PBR, defined as an Oil and Gas Site ("OGS"), shifts from project to project. Moreover, only one PBR may be claimed per OGS. See proposed §106.352(b)(5)(C) (providing that "{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"). Accordingly, facilities that must be aggregated under the proposed PBR include those facilities or groups of facilities that are "directly operationally related" and "located no greater than a 1/4 mile from the facilities associated with a project requiring registration under this section." This definition works well for the first project. However, an OGS-boundary creep will occur as new projects take place over time. As the OGS 1/4 mile radius boundary adjusts and creeps on a project basis to authorize new projects, existing facilities could be dragged into one or more PBR authorizations claimed sequentially over time, depending on their location relative to each new project. Layer on top of that the requirement that only one PBR may be used per OGS and the result is that a single facility can be authorized by sequential PBR registrations depending on the point in time in question. Compliance would be impossible to determine because identification of applicable PBRs for a particular facility would be administratively impracticable. For example, for years 1 - 3, Facility A is authorized under the PBR for Project 1; for years 4 - 5 Facility A is located within 1/4 mile of Project 2 and gets included the OGS and authorized by Project 2 PBR, and so on."

The commission has changed the rule in response to this comment. The

commission has also revised the scope of registration expectations and established a fixed boundary, and removed all references which would have established an inappropriate "creep" of the state minor source authorizations.

TPA commented that, "Instead of reviewing the applicable permit or PBR for a particular facility, the regulated entity and the enforcement staff of the TCEQ would have to look at authorizations through the lens of a "project" applicable to the point in time in question to determine if the facility was validly authorized and/or in compliance with applicable requirements. The recordkeeping would be complex and untenable at best. Enforcement would be practically impossible. If one or some of the sites were Title V sites, tracing the facility from Title V permit to Title V permit and certifying its compliance would be a nightmare. Moreover, deviation reporting would be so complex that it would be virtually meaningless. In short, it would simply be impossible to administer this program. This is a fatal flaw in the PBR as proposed."

The commission has not changed the rule in response to this comment. The commission respectfully disagrees that the concept of "project" to determine a point in time when certain applicable requirements are triggered is new, unenforceable, or untenable. This concept as applied to historical permitting, including sites which have expanded over time under Standard Exemptions, PBRs, standard permits, case-by-case permits and federal NSR permits, have used this approach since its inception in 1972 and the entire system of enforcement on the state and federal levels accounts for changes over time.

TPA stated that, "The root cause of this conceptual flaw is that the PBR is tied to a site; and site is defined in part with reference to a "project." TPA acknowledges that the reason TCEQ staff designed the OGS PBR in this manner is to assure protectiveness of existing and new facilities. In fact, TPA recognizes that multiple nearby projects are just the type of situation that TCEQ is attempting to address. However, protectiveness can be addressed through other means and does not have to be based on a boundary-shifting site-wide PBR. Discussions of this issue with TCEQ staff reveal that staff acknowledges the inherent problem with the proposed structure and that staff wishes to correct the problem. Indeed, staff has indicated in informal meetings that it intends to abandon the use of the term "Oil and Gas Site" throughout the PBR and in its place use the following terms: 1) "Project" — would be used in place of OGS. 2) "Scope of Registration" — would identify the facilities authorized by the PBR. 3) "Scope of Protectiveness" — would define the sources that must be included in a protectiveness review. 4) "Scope of Impacts Review" — would relate to a property line or receptor review."

The commission has changed the rule in response to this comment. The commission has changed the PBR rules to clarify that boundaries of registrations do not shift over time, and has changed the definitions of "project", "registration", and the scope of impacts evaluation in response to this and similar comments, thus resolving the concerns expressed on this issue.

TPA commented that, "It appears that the use of these concepts would or could be workable solutions to the problem, depending on how the terms are defined and used throughout the PBR. However, it is simply not possible for the regulated community to comment intelligently on these verbal indications by staff without seeing the proposed rule text. As much as we would like to be able to support TCEQ in its goal of achieving an enforceable, protective and updated PBR for the oil and gas industry on an expedited timeline, without seeing concrete regulatory language we are not able to determine the impact of these new concepts on our operations. We would encourage the TCEQ to republish, amend, or present the public with an updated draft of the PBR using these concepts as soon as possible, as they may indeed prove to remedy many of TPA's concerns."

The commission has changed the rule in response to written and verbal comments and alternatives presented. The commission appreciates industry perspectives and has evaluated all written and verbal comments and alternatives presented by stakeholders to promulgate reasonable, understandable, and clear regulations for this industry under the PBR and standard permit.

ETC "believes that the definition of Oil and Gas Site ("OGS") in subsection (b)(3) of the proposed PBR and Standard Permit should be revised. The scattered provisions that make up the definition should be collected in one place. We propose the following revisions to add: (D) Located within a circle with a fixed radius of 1/4 mile at the time the PBR is claimed or registration occurs; (E) Are operationally dependent on one another; and (F) Are not already authorized under this section. ETC recommends the rule be changed to: 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 with same two digit standard industrial classification (SIC) Codes; (D) Located within a circle with a fixed radius of 1/4 mile at the time the PBR is claimed or registration occurs; (E) Are operationally dependent on one another; and (F) Are not already authorized under this section."

The commission partially agrees with the comment. The commission respectfully declines to make changes based on this comment in subsection (b)(3), but has revised the definition of registration and project in subsection (b)(5) with similar, but not the same, changes.

TPA commented "In any rule, but in particular a rule such as this, clarity is needed in the applicability provisions and in defined terms. Important provisions for the definition of OGS are scattered in several sections of the rule; for example, three components of OGS appear in subsection (b)(3) and include the concepts of contiguous and adjacent, common ownership and control, and common SIC code. In subsection (b)(5)(C), the concepts of "located no greater than 1/4 mile from the facilities associated with a project" and "operational dependency" are stated. This language is the core language that drives the PBR boundaries to shift project-by-project and is the basis for our comments discussed more fully above. The result is that the drafting imprecision of these very significant terms creates lack of clarity in terms of the very basic applicability of the PBR. Not only is the presentation of the core elements of the definition of a site confusing, but key terms within that definition are themselves undefined. For example, what does it mean to be "operationally related"?" What is a "project," and what facilities are considered to be "associated with a project"? TPA does not have answers to all of these questions because answers and development of definitions for these terms would take hours of dialogue with staff and membership, valuable hours that the timing of the process has simply not allowed. However, TPA does suggest that, at a minimum, TCEQ consider the following revision to the definition of OGS in subsection (b)(3): (D) Located within a circle with a fixed radius of 1/4 mile at the time the PBR is claimed or registration occurs; (E) Are operationally dependent on one another; and (F) Have not been claimed in or covered by another OGS PBR. Further TPA states Use of a PBR to authorize a "site" instead of a "facility" is not permitted by statute. (See THSC, §382.05196: "the commission may adopt permits by rule for certain types of facilities if it is found on investigation that the types of facilities will not make a significant contribution of air contaminants to the atmosphere" (Emphasis added). Staff has suggested narrowing the scope of coverage of the PBR away from "site" towards a narrower concept of "project," "scope of registration," "scope of protectiveness," and "scope of impacts review." This may resolve our issue concerning the breadth of coverage for the PBR. But we would like to have more information about this concept. TPA recommended specific language: OGS is defined as all facilities which meet the following: (A) Located on contiguous or adjacent properties; (B) Under common interest and control; (C) Designated under the same two digit standard industrial classification (SIC) codes; (D) Located within a circle with a fixed radius of 1/4 mile at the time the PBR is claimed or registration occurs; (E) Are operationally dependent on one another; and (F) Have not been claimed in or covered by another OGS PBR."

The commission has changed the rule in response to this comment. The commission appreciates that several stakeholders and commenters are confused and has revised subsection (b) to include definitions of project, registration, and clarified other terms.

Pioneer requested that the commission to "please define "project" as it is not defined anywhere throughout the proposed rule and is referenced often."

The commission agrees with the comment to define "project" and has changed the

rule to include this definition.

EDF stated that the rule "should define what is meant by the word "project." For the same reasons discussed in the section above entitled "Level of overall health protectiveness", the definition of project should at a minimum include all emissions at an oil and gas site. This change is needed to ensure protectiveness of health. If such a change is not made, the requirement of §106.352(a)(1) that only one PBR for an oil and gas site (OGS) may be claimed or registered would seem to be rendered meaningless."

The commission agrees with the comment to define "project" and has changed the rule to include this definition. The commission respectfully declines to establish this definition to include all emission sources at an OGS, and instead uses "project" as only a part of the criteria for sources to be considered in the impacts evaluation for protectiveness as outlined in subsection (k).

ConocoPhillips requested that "consistent with other NSR permits, the trigger for the revised PBR be a project or a physical change or a change in the method of operation that impacts facilities at an oil and gas site. If the project or the change results in a net increase in emissions in excess of the thresholds identified in Section (c)(1)(B) of the revised PBR, it would trigger the need for a registration. A common sense definition of an oil and gas site generally within set property lines would serve well in conjunction with the concept of a project. There are additional regulatory and guidance documents that add definition to the concept of a site. We recognize that a site could then potentially have multiple PBRs. We also recognize the concern about stacking of PBRs."

The commission has revised the rule in response to this and similar comments and defined project consistent with other NSR permitting actions. The commission has also revised the scope of registration expectations and established a fixed boundary in order to provide certainty to the regulated community and the public.

Registration

Senator Wendy Davis recommended changing the section to read "at the time a PBR is registered. One could attempt to argue that the only receptors covered are those in place at the time the rule is promulgated, not at the time the permit is sought."

The commission agrees that the intent of this subsection is not to cover only those receptors which are in place at the time that this rule is promulgated. This subsection covers receptors which exist at the time a PBR is claimed (registered or certified). The commission confirms that this language was proposed, and will be adopted, for this PBR.

The TPA" discourages this administrative expansion of the scope and coverage of PBR authorizations. We recognize that a paramount driver for the TCEQ's efforts in revising the PBR is to ensure protectiveness of the facilities authorized by the PBR, which TCEQ believes can be accomplished only by elevating the PBR to a site-based authorization. However, TPA believes that protectiveness can be achieved through other means, such as a review of project emissions as is performed for federal NSR permitting, compliance with newly promulgated RICE MACT standards, and imposition of new controls on existing sources through state implementation plan provisions and other known processes. It is not necessary for the TCEQ to turn a longstanding and well understood permit authorization into a site-wide authorization that is complex and hard to understand, and that will result in a compliance nightmare. Importantly, TPA believes the TCEQ is acting outside the scope of its authority in doing so."

The commission has changed the rule in response to this comment. The commission has revised the definition and scope of "project", "registration", and impacts evaluation requirements and exemptions in response to this and similar comments. The commission respectfully disagrees that in general relying solely on federal 40 CFR Part 60 NSPS, 40 CFR Part 61, 40 CFR Part 63 NESHAP and preconstruction federal permitting is sufficient to demonstrate and ensure compliance with the TCAA as the federal rules and regulations have a statutorily different purpose than state minor source permitting. However, in the case of formaldehyde and engines, after a detailed review of submitted information and federal background documents for 40 CFR 63 NESHAP Subpart ZZZZ, the commission has determined that the requirements of this federal standard is sufficient to establish controls on formaldehyde on new and existing engines. This is further supported by recent monitoring and does not show any concerns with monitored values of formaldehyde from engines associated with oil and gas production sites. Therefore, formaldehyde is omitted from the impacts evaluation requirements and emission limits for this PBR.

El Paso comments that "the previous version of §106.352 did not require registration unless a facility handles sour gas."

The commission has not changed the rule in response to this comment. The commission agrees that the revised PBR changes the criteria for registration from the previous version of this PBR which was last substantively changed in 1986.

Senator Wendy Davis stated "The registration date should be moved up (shortened) to more quickly protect the public."

The commission has not changed the rule in response to this comment. The commission has included practical deadlines for projects in the Barnett Shale and the remainder of the state consistent with agency resources necessary to effectively implement these requirements. These deadlines will also allow sufficient transition time for industry consistent with the deadline for submitting an authorization for planned MSS is set in §101.222(h)(1).

TXOGA asked "if the notification is a requirement regardless of whether or not an application has already been submitted to the TCEQ or not? Sites that have submitted an application already should be exempt. What is meant by identifying information? More detail needs to be provided on this for comment."

The commission has clarified the rule in response to this and similar comments and questions. The notification will only be required for unregistered historical sites and not new projects. The identifying information will consists of the

following; rule claimed as authorization, lease name, well number, latitude, longitude, and information collected on the TCEQ Core Data Form.

EDF states that they see "no reason why information under this paragraph should not be provided sooner than January 2013. We suggest this date be changed to 1 year from the effective date of the rule so that the agency has the necessary information needed to formulate sound public policy in the future."

The commission has not changed the rule in response to this comment. The commission believes that January 1, 2013 will give industry ample time to notify the agency and will give the agency sufficient time to compile the data to be used in the future.

TXOGA commented that, "When a facility does not certify emissions below the 25/250 limits of §106.4 during a site registration, then changes to the site do not require additional registrations. Change the term registration to certification."

The commission has not revised the rule wording due to the definitions established in subsection (b) for project and registration. The proposal version of subsection (c)(1)(A) also had specified that emissions increases must only be over certified levels before requiring a new registration.

Senator Davis recommended that, "Operators not be allowed to side-step the requirements of §106.352 through the use of §106.264, Replacement of Facilities."

The commission has changed the rule in response to this comment. The commission agrees with the commenter and has specifically included subsection (c)(1)(B)(iv) to cover replacement of facilities under §106.352.

ETC stated that, "Replacements or modifications that do not change the character or increase the quantity of emissions should not trigger coverage by the new PBR, A replacement or modification should not trigger application of the new PBR or Standard Permit requirements unless it results in a change in the character of emissions or an increase in the quantity of emissions. If a replacement results in more hp but fewer emissions, it should not be a triggering event; similarly, if a modification does not result in increased emissions, it should not be a triggering event. As currently drafted, the proposed PBR and Standard Permit would include within the scope of covered facilities those that do not increase the quantity of emissions and even those that reduce the quantity of their emissions (See subsection (b)(5)(B) of the proposed PBR and Standard Permit, requiring inter alia impacts review even for unchanged sources). The inclusion of such language in the PBR would contradict the accompanying Executive Summary, which states that "{o}il and gas facilities currently authorized under a PBR and that remain unmodified are not affected by this proposal except for identifying notification and planned MSS." Like-kind replacement of facilities should not be subject to subsection (e) if the replacement will not result in an emissions increase. As currently proposed, subsection (c)(1) would subject replacement of any facility to the best management practices requirements and other provisions set forth in subsection (e). Such a requirement would be unduly burdensome in certain situations. For example, if the replacement is a like-kind replacement, and is one that will not result in an emissions increase, then it should not be subject to subsection (e) because no impact upon environmental conditions will be caused by the change. For all practical purposes, such a "change" represents a continuation of prior practices. Indeed, if anything, a like-kind replacement is likely to be environmentally beneficial because such replacements are often made in order to replace older, less efficient equipment with newer, more efficient equipment. ETC believes that subjecting such replacements to the requirements of subsection (e) would create a disincentive to install new, more efficient equipment. It is our understanding that TCEQ does not want the PBR to contain disincentives to making environmentally beneficial changes at sites. Accordingly, ETC proposes the following revisions to subsection (c)(1). The use of the term "like-kind" in the proposed revision above is taken directly from the rule's preamble, where it is clearly stated that subsection (c)(1)(C) is intended to cover like-kind replacements. If a replacement, such as a like-kind replacement, does not change the character or increase the amount of emissions, then it should not be subject to the best management practices provisions of subsection (e). Therefore, the above revisions are required so that the agency's intent is reflected in the actual rule text."

The commission has changed the rule in response to this comment. The commission agrees with the commenter and has included in the language of subsection (c)(1)(B)(i) to cover "any other new facilities", which includes replacement facilities, as well as subsection (c)(1)(B)(iv) which specifically allows replacement facilities " if the new facility does not increase the previous actual or certified emissions" to be exempt from registration. However, due to the limited,

but essential nature of maintaining equipment in good working order to continue to minimize emissions, the commission continues to require these changes to meet best management practices. In response to the perceived burdensome nature of BMP, additional justification is provided for subsection (e) requirements, and changes have been made to subsection (j) to allow for any existing records to be used for compliance. Additionally, the commission changed recordkeeping requirements for negligible changes from records being kept over any period of time to records needing to be kept for a rolling 60-month period.

One individual stated that, "The proposed "Permit By Rule" ("PBR") will work to disincentives existing facilities from upgrading their equipment by including "Modified" facilities within the scope of regulation. This phenomena will work to undermine the objective, common to both the natural gas industry and environmentalists, of continually decreasing, through technological advances in equipment, waste gases emitted into the atmosphere by such industrial sites. It simply fails to make practical sense for companies to be exposed to greater regulation because they invest in "cleaner" equipment. These companies should be rewarded, not condemned, for their desire to invest in our environment."

Devon commented on subsection (c)(1)(C). "For existing OGS, the replacement of any facility is authorized without registration provided that the previously registered emissions or potential to emit do not increase; however, the OGS is subject to the Best Management Practices (BMP) in subsection (e). It is unwarranted to require BMPs for OGS that do not increase emissions. The triggering of BMPs could cause unjustified and expensive retrofits and replacements to equipment on site. Devon strongly recommends that changes to a site that do not increase emissions, potential-to-emit, or increase production capacity should not require BMPs. Such requirements may actually create disincentives for replacing older equipment at an OGS."

Encana commented on §106.352(c)(1)(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. Encana Response: The above provision potentially conflicts with provision subsection (b)(5)(B) which states: "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" Encana believes that if the replaced facility does not change its "certified" character or quantity of emissions that facility should not be subject to the provisions of subsection (e) Best Management Practices."

The commission has changed the rule in response to this comment. The commission has included numerous exemptions from registration requirements various small and incidental changes at OGS to limit the regulatory burden in these instances, even including small increases in emissions. The commission believes this flexibility will provide incentives for technology upgrades for replacement and modified facilities where emissions are minimized. To ensure these emissions remain limited, best management practices are applicable to maintain equipment in good working order. In response to the perceived burdensome nature of BMP, additional justification is provided for subsection (e) requirements, and changes have been made to subsection (j) to allow for any

existing records to be used for compliance.

TPA commented on subsection (e): "the BMP provisions need revision to clarify that they only apply to new and modified facilities. The BMP provisions are internally inconsistent. While the lead-in applicability provision states that new and modified facilities and associated control equipment must meet the requirements of subsection (e), the following subsections are not clear as to whether the applicable BMPs only apply to new and modified facilities. For example, the first sentence of subsection (e)(1) states "{a}ll facilities which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations." And, the second sentence of subsection (e)(1) states: "{e}ach site shall establish and maintain" a BMP program. (Emphasis added.) Yet the preamble provides that the BMPs and minimum requirements in subsection (e) "are not applicable to existing, unchanged facilities at an OGS." (See 35 TexReg 6949). While TPA does not object to this requirement as a general requirement, to place it in this subsection, which is intended to apply to new and modified facilities, creates ambiguity and confusion as to the scope of this subsection's coverage. When queried about the uncertainty of the applicability of the BMPs, staff responded that it intentionally drafted this language ambiguously in an attempt to prompt comments on this issue. TPA submits that the applicability of the BMPs should be unambiguous, that they should only apply to new and modified facilities at an OGS that trigger coverage under the new PBR, that the entire OGS should not be made subject to the BMPs by virtue of having one or two or some facilities authorized by the OGS PBR, and that clarifying language should be peppered throughout subsection (e) to provide this clarity. Subsection (e): Add the following sentence to the end of subsection (e): "The requirements in this subsection (e) are not applicable to existing facilities at an OGS that are not part of the project triggering registration under this section.""

The commission has revised the rule language to state BMP requirements are not applicable to existing, unchanging facilities at an OGS.

Kinder Morgan commented that, "Due to the various definitions and interpretations of "replacement" the language of the rule must clearly indicate the type of replacements that trigger registration and application of the new PBR."

The commission has not changed the rule in response to this comment. The commission has included in the language of subsection (c)(1)(B)(i) to cover "any other new facilities", which includes replacement facilities, as well as subsection (c)(1)(B)(iv) which specifically allows replacement facilities "if the new facility does not increase the previous actual or certified emissions" to cover all possible situations where new facilities replace existing facilities either in a like-kind scenario or upgrades.

ETC proposed that subsection (c)(2) be clarified as follows: "All registrations that are required under this section shall meet the following:"

The commission has not changed the rule in response to this comment, but instead has clarified projects and registration expectations in subsection (b).

Representative Burnam recommended increasing permitting fees to $200 for small business or nonprofit government operators and $900 for others in nonattainment areas to increase the incentive to meet level one emission limits.

The commission has not changed the rule in response to this comment. Maximum fees for PBRs are established in §106.50, and is beyond the scope of this rulemaking.

The City of Fort Worth commented that "the documentation for proposed rules is voluminous and its organization makes it difficult to determine which standards and controls are applicable under a given set of circumstances. It is not remotely reasonable that the public can ascertain which requirements apply to a given site by navigating through 200+ pages of documentation as described in the proposed rules. A much more understandable format would be to issue a set of clear requirements along with a separate technical support document providing the rationale for the rules. However the Oil and Gas PBR is an example of why an actual, tangible, and site-specific paper permit should be required for each of these sources, particularly in rapidly growing urban areas with many area sources. Such a permit would specify the exact regulatory requirements for the individual site. Although the conditions could be standardized, the permit should state each emission unit, its corresponding emission control requirements, and its maximum allowable emission rate. This allows the operator of a site to clearly understand the applicable requirements for that site and also allows the public a reasonable opportunity to ascertain if the site is in compliance."

The commission has not changed the rules in response to this comment. In order to cover the great diversity of facility combinations, and the insignificant amount of many source emissions, it has been determined that specific, stipulated parameters and controls are not necessary. However, registration-specific information is required to be submitted and available in the public record for review and compliance demonstrations. This information is expected to be submitted through the ePermits system.

The Sierra Club and two individuals stated "that they would like to see the proposed electronic ePermit registration system for regulated entities be made publicly accessible."

The commission continues to develop the ePermits system and will consider this request as future updates occur.

Senator Davis requests the commission "Examine the TCEQ's existing permit fees and fines and recalibrate those so that industry is bearing the cost of overseeing its activity."

The commission has not changed the rule in response to this comment. Maximum fees for PBRs are established in §106.50, and is beyond the scope of this rulemaking.

TAEP commented that, "90 percent of the regulatory and compliance effort will be directed to

10 percent of the oil and gas emissions. Of the 375, 000 active facilities in the state, tens of thousands produce less than 3 BOE (barrel of oil equivalent) per day. If these facilities were vented to the atmosphere (and they are not), only a very few would meet the levels of emissions of the Level 1 PBR. Production is reported to the Texas Railroad Commission." Additional information on marginal wells and operations was submitted by TAEP, PBPA, TXOGA, and TPA.

The commission has changed the rule in response to this comment. After review of the existing protectiveness evaluation in conjunction with research by staff on typical small operations and submittal of clarifying information on actual operations by industry, the commission has included an exception for small operations in subsection (c)(4) - details are included in the SECTION BY SECTION ANALYSIS. In addition, the commission has adjusted the emission limits in Level 1 to accommodate a higher percentage of the actual oil and gas facilities in the state, while ensuring these limits are reasonable and protective.

Encanca commented that, "The TCEQ could benefit from a simplified "self-certification" registration on all sources smaller than Level 2 over a 1-year period."

The commission partially agrees with this comment and will be using an automated ePermits system for both Level 1 and 2 notification and registrations. The outcome of implementing this process will be an immediate response from the commission for registrations and certifications.

Encana commented that the "TCEQ could expedite the ePermitting process review, developing standardized forms, checklists and guidance documents before the rules are finalized and become implemented."

The commission has changed the rule in response to this comment. The commission is developing a standardized Oil and Gas spreadsheet for use in calculating emissions and published the draft on the agency website for external stakeholder input as of October 29, 2010. The commission will also provide checklists and guidance documents that will be available on the TCEQ website. In addition, the commission is planning on sponsoring short workshops around the state to assist companies in preparing registrations and compliance records before the effective date of the rules.

TAEP commented orally that, "Pre-construction review is unnecessary in most cases because these facilities are subject to enforcement. This only serves to slow the process and retard production." The followed in writing that, "Preconstruction Review is un-necessary to assure compliance with the NAAQS or the state ESL's since the applicant sis performing under the impact analysis using the TCEQ's model. The applicant is subject to enforcement. Time delays and unwarranted procedures can be eliminated by: Establishing a mandated turnaround by TCEQ on applications; Limit preconstruction review to facilities in nonattainment areas; establishing more reasonable emissions standards for preconstruction review."

Devon commented that, "Requiring approval prior to construction for sites with 10 tpy or greater of VOC is contrary to the intent of the PBR, which is a streamlined authorization for insignificant emission sources that allows for post-construction registration. Requiring pre-construction approval (Level 2 PBR) for oil and gas sites with emissions greater than 10 tpy VOC is contrary to the intent of the PBR, which is a pre-construction authorization process for sites with emissions considered to be insignificant sources as identified by the TCAA. A 10 tpy threshold for an OGS is a very small threshold and will result in production delays and lost state revenue across Texas. Further, if an OGS emits 10 to 20 tpy VOC, there are limited options to control down below 10 tpy other than installing flares, in which case VOC emissions are traded for increased NO_X emissions, an ozone precursor. A VRU requires more significant volumes to operate properly, thus control options are limited for OGS in the 10 to 20 tpy VOC range. TCEQ's actions in this regard appear impractical and economically infeasible. Therefore, Devon recommends TCEQ drop any pre-construction permitting requirement, which is inappropriate for insignificant emission sources eligible for PBRs or, in the alternative, revise the Level 2 PBR threshold for pre-construction authorization to 20 tpy VOC. With regard to the Level 2 PBR pre-construction application process, Devon recommends requiring a basic pre-construction application form that includes a range of expected operating parameters and data within the operating company's best estimate. This would provide the TCEQ with basic site identifying information and scope of work, rather than requiring a full permit application prior to production. Establishing a reasonable timeframe for review and approval, such as 15 days, is recommended and should provide adequate time for TCEQ processing. A full permit application would then be submitted following initial startup of operations, which would provide the TCEQ with the most accurate emissions calculations for permitting purposes and would not unduly delay the permitting process."

TPA commented that, "The Level 2 Preconstruction Approval provisions in subsection (h) of the proposed PBR should be revised. The traditional purpose of a PBR has been to promote efficiency and ease of administration by allowing operations meeting certain requirements to commence without awaiting agency approval. As noted elsewhere in these comments, the proposed PBR's Phase 2 rules would eliminate these benefits and would replace them with a process that would not be much different from that used in the context of ordinary permitting. It would inject case-by-case decision making into the PBR process, thus eliminating the efficiency that, to date, has been the hallmark of the PBR process in Texas. It would also dramatically slow down oil and gas production in the State, thus harming the economy and negatively impacting the State's budget. To address this issue, TPA proposes the following revision to subsection (h)(2) of the proposed PBR: If an OGS meets the following, the facilities must be registered and approved prior to start of construction or implemented changes, whichever occurs first. TPA also stated that Pre-approval requirements required by Level 2 should be eliminated because they too are inappropriate in a PBR that is intended to apply to insignificant sources, and further because any requirement to obtain pre-approval would deprive owners and operators of the nimbleness and flexibility that a PBR is supposed to provide for those who are covered by its terms."

Targa stated that in "In 2009, Targa submitted 24 Permit by Rule ("PBR") registrations under the existing §106.352, largely to add or remove a compressor engine and update the §106.352 documentation to reflect the change. All of these projects would have required Level Two Preconstruction Authorization due to the amount VOC emitted from the site. The nature of the proposed rule turns the PBR process into an unknown and indefinite process. The benefit of

Texas's PBR program is to concentrate resources on important and larger emissions sources. As such, Targa requests that the Level 2 Authorization continue to be a registration process and not an approval process. The company bears the responsibility of failure to comply."

Encana commented that, "The TCEQ could avoid delays in the permitting process establishing timing for response from TCEQ for Level 2 pre-construction registrations. Section 106.352(h)(4)(B) and standard permit (g)(2)(A) Encana Response: Encana understands that the pre-construction registration requirement has been included to ensure that the commission has the opportunity to review emission estimates for protectiveness evaluations and NAAQs {sic NAAQS} compliance. However, as proposed, the rule does not give any minimum time for the Commission to respond to the permittee as required under other NSR permits. Not including a review time period in the rule could potentially delay construction and/or modification for months and create a backlog for the TCEQ."

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "For wells that are drilled in new fields or new formations, it is very difficult to predict what the production and pressure of the well will be once it is drilled. This could lead to underestimation of emissions in the application for a Level 2 or a standard permit which require an application prior to construction. Even in established fields with fairly consistent production and pressures from each new well, you can occasionally have a well that comes on with a higher production or pressure that could make emission higher than initially thought. It is difficult to estimate the production of an individual well until it is cleaned up and producing steadily. Furthermore, well production declines over time. The first 180 days production is the highest production from a well and there is rapid decline after that. If this occurs, it is outside of the control of company operating the well. Option 1: If an OGS project meets the following, the operator must submit a notice of intent of an application prior to start of construction or implemented changes, whichever occurs first. Then the operator must submit a full application within 90 days of completion of construction or implemented changes, whichever occurs first. After any recovery or controls, the OGS must have the potential of less than..." With oil and gas production there are contracts and agreements that stipulate when the well must be drilled and produced. With no deadline for TCEQ response on the air permit authorization, there is no way for companies to plan to make sure the other contracts and agreements are met. Furthermore, TCEQ is planning on providing a standardized calculation template, therefore, review time should be shortened by the TCEQ. Please provide 30-day limit to the review and response by the TCEQ to be consistent with Pollution Control Project Standard Permit. Only require registration if primary authorization is this version of PBR."

TXOGA went further to state that "Requiring insignificant emitting facilities that emit greater than 10 TPY VOC be registered and approved prior to construction is overly burdensome for insignificant OGS and a requirement that is not applied to comparable sites in other industries. Sites with as little as 1 barrel per day of condensate production would be required to wait for written authorization to start construction. The delay in production while waiting for approval could cost the state millions in lost taxation revenue, require additional agency funding and have negligible, if any, ambient air quality impact. These regulations give no minimum time for the TCEQ to respond as required under other PBRs. For instance, §116.617(d)(1)(B) states construction can begin if TCEQ does not respond in 30 days. Due to other contractual agreements the wells must be drilled and producing within a certain period of time. Not giving a review time period could hold up construction for months even though the emissions are only 11 TPY which is unreasonable. Where did the arbitrary 10 TPY come from? Furthermore, this will result in multiple submissions for every location because you do not know the production of a well prior to drilling the well. TXOGA recommended changing these requirements to "must be registered 180 days after start of operation or implemented changes."

TPA commented that, "The PBR in some instances would even require entities to obtain approval from agency staff prior to undertaking a new project, in a manner no different from case-by-case permitting under 30 TAC Chapter 116. Indeed, a major flaw in the proposed PBR is that it would create excessive need for case-by-case review. For example, the proposed impacts reviews and modeling demonstrations would drive site-specific emission limits. In addition, the requirement in the Level Two context that preconstruction approval be obtained would create a situation where agency judgment would have to be exercised on an ongoing, particularized basis. The inclusion of provisions that are not self-executing but that would instead require the exercise of judgment by TCEQ staff (and occasionally, pre-approval by TCEQ) would add complexity to a permitting process that is intended to be the simplest form of permitting at the TCEQ. It would also defeat the very purpose of a PBR and would jeopardize the possibility of EPA concurrence and approval. And, in the case of the Level Two preconstruction approval requirement, it would have the potential to impair the nimbleness needed by industry in order to quickly respond to new or changed conditions at an oil and gas site."

The commission has changed the rule in response to these comments. The commission partially agrees with this comment and will be using an automated

ePermit system for both Level 1 and 2 notification and registrations. The only information needed prior to construction of facilities will be Core Data and a brief description of the project. This notification will be through the ePermits system and have an immediate acknowledgement from the commission. Additional detailed information will not be required for at least 90 days, and again will be submittal through the ePermits system with an immediate response. This process is intended to provide information to the public and commission, as well as ensure no economic delays.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "The proposed registration requirements will force compressor sites to be registered under this PBR even if authorized under historical Standard Exemption/PBR and included MSS emissions then since all historical must comply with MSS provisions. Clarify, that the original authorization is still enforced and should not require registration provided the proposed criteria is still met (protectiveness)."

The commission has changed the rule in response to this comment. The commission has revised the rule to make it clear that historically claimed Standard Exemptions or PBRs remain in effect for production emissions from unchanging existing facilities.

ETC and TPA commented that the "PBR registration should not be required, whether under Level I or Level 2, until such time as TCEQ's proposed ePermitting system is fully functional and operating properly. In the interim, owners and operators should be allowed to simply claim coverage by the PBR, without any registration requirements."

The commission has not changed the rule in response to this comment. The commission agrees that to ensure a smooth implementation, the ePermits system should be available for notifications and registrations as required by the rule. The commission fully intends to have a working system by the effective date of the PBR. In the case of the ePermits system not being available, the rule also provides for hard-copy submittals by companies and also does not require operators to wait on responses to construct or operate facilities as long as all requirements are met.

Conoco Phillips suggested the following with respect to Scope of Registration: "a) The multi-tiered registration process should be replaced with a single registration within 180 days of construction for all PBR eligible projects. At a minimum, the preapproval requirement should be removed. b) The lb/hr requirement for triggering the PBR should be removed retaining the existing thresholds of 25 tpy of VOC/SO_2 and 250 TPY NO_X/CO."

The commission has changed the rule in response to parts of this comment. The preconstruction registration requirements have been replaced with notification and 90-day or 180-day follow up registration. The hourly limits have not been changed in response to this comment, but values have been adjusted based on other comments made by this and other stakeholders.

Pioneer commented that, "There is no turnaround time stated in the proposed rule for receiving the preconstruction authorization from the TCEQ. This is extremely problematic because the entire project will be placed on hold awaiting a response by the TCEQ. Unanticipated delays will cost money, time, and disrupt construction and production schedules that are so vital for oil and gas businesses to run effectively. Further, due to contractual agreements, the wells must be drilled and producing within a certain period of time. Pioneer recommends a 45-day response timeframe from the TCEQ for Level 2, §106.352 PBRs, concurrent with the current Standard permit regulations."

The commission has changed the rule in response to parts of this comment. The preconstruction registration requirements have been replaced with notification and 90 to 180-day follow up registration submittal through the ePermits system with an immediate response. This process is intended to provide information to the public and commission, as well as ensure no economic delays.

Sierra Club and an individual commented that the time periods for post-construction registration PBRs are too long."

The commission has not changed the rule in response to this comment. After further analysis of comments, the commission has created a combined notification and registration system. Information on new projects will be required prior to construction, and information would be electronically submitted and available on-line almost immediately. The Central Registry and APD databases will contain

information on the location and expected project scope. Within a short period of time, registered or certified information will be submitted for equipment, materials, and operations. This delay will provide an opportunity for confirmation of such details which are essential to accurately estimate emissions, and longer periods of time are only allowed for the smaller groups of facilities.

EDF commented that, "Due to the very rapid development observed in the Barnett Shale area and the well-established influence of emissions of ozone precursors in the East Texas Region on ozone levels within the Region, TCEQ should avoid long lag times between the start of operations and the notification requirement for new sources. Accordingly, Level 1 registrations in a nonattainment area or in the East Texas region should be registered within 45 days of well completion."

The commission has not changed the rule in response to this comment. Any oil and gas facility or group of facilities in a designated nonattainment area is subject to more stringent requirements (30 TAC Chapters 115 and 117) than those required by the PBR. With greater restrictions, and correspondingly limited emissions, there is no reason to rush the registration timing and potentially get less accurate equipment, materials, and operations information.

Encana proposed "an alternative for Level 1 sources similar to the approach taken by the State of Montana, Montana's approach includes filing a "self-certification" registration. TCEQ should consider applying this approach on all sources smaller than level 2 over a 1 year period, starting

January 1, 2011, However, those Level 1 sources should better defined. For example, wellheads with only a meter run would be exempted (no material emission sources). The use of emission factors and representative gas and condensate analysis for all Level 1 calculations should be allowed. The Level 1 registration would be a one-time submission unless a change causes the estimated emissions to exceed the Level 1 thresholds."

The commission has changed the rule in response to this comment. For the representative analysis, representative gas and liquid analysis will be accepted for registration purposes if they meet the criteria. The Regional office may at any time request a site-specific gas and liquid analysis, as is part of their requirements.

A representative analysis of gas or liquid at an OGS may be used in the following circumstances: 1) the wells must be producing from the same reservoir and formation; 2) the initial and final separation must be at similar pressure and temperature, within 10 percent; 3) similar fluid composition with similar API gravity (within two degrees), oil site (API of 40 or less) with associated gases, or natural gas site with associated liquid hydrocarbons (API of 41 or higher), or natural gas site that is "dry"(less than 2 barrels per MMSCF) 4) sites must process the stream in the same manner, same number and stages of separation, dehydration, and sweetening and 5) are within several miles of the site sampled. It is recommended that the site that would yield the highest estimate of emissions be used as the representative. This will ensure that any other site that is using this representation should be less than the site actually sampled. Region may request

at any time a specific site sample. This is an acceptable criterion because the same reservoir will have the same basic characteristics of material component if it is within a small area of the reservoir. The gas and liquid needs to be processed in a similar manner since this can greatly affect the amount of VOCs entrained in any of the streams. API gravity is used to differentiate between oil and condensate streams. An API gravity of 40 was used since the ESLs for crude and condensate were based on whether the liquid had an API gravity greater than or less than 40. The streams must be treated similarly, since the output of one process may be in the inlet to another process. Since even within the same reservoir and formation the character of the stream being processed can vary greatly, samples must be taken throughout the field, thus no represented stream should be more than 5 miles from the sampled stream. The commission also understands that there are not enough labs to do all the required sampling and analysis. Representative analysis will not work for determining H_2S content of the stream. Each site will have to know the content for that stream, since it can vary greatly in a field and formation. However, to minimize cost a simple test such as a stain tube or dragger tube can be used. Sites with H_2S too high to use these simpler types of test methods will have to have an analysis done by GC.

Pioneer commented that, "It is difficult to estimate the production of an individual well until it is cleaned up and producing steadily. Please consider the following scenario where a well is estimated to emit less than 10 tpy VOCs and produce under the threshold for the other chemicals listed under Level 1, so the well operator submits the PBR application after start of operation, but then the well begins producing above Level 2 threshold limits. Will there be enforcement action and/or penalties associated with this unforeseen event? Is the operator to shut down production and submit a Level 2 application, then wait for approval, for which the time frame is currently undefined because the proposed rule is silent on this point, before resuming operations? This delay could be an enormous financial burden and disrupt crucial timetables and contractual obligations. Pioneer requests that TCEQ delete the preconstruction authorization requirement from the, PBR or provide some useful and realistic guidance for this common scenario that will not shut down operations for an undefined, possibly lengthy, period of time."

TIPRO commented that" The TCEQ should recognize that the type and proportion of products (gas/liquids) may be uncertain until after the process of extraction has started. A 180 days after startup registration allows enough time to gather the necessary information to gather accurate site information (data) to determine what level of permitting (Level 2 or Standard Permit) is required for the facility (if new) and submit a complete application reducing correspondence and paperwork between the applicant and the TCEQ. However, if the TCEQ determines that pre-construction notification is necessary and needs to stay in the rule; the TCEQ should recognize that the rulemaking does not give any minimum time for the Agency to respond as required under other NSR permits. Not giving a review time period could hold up construction and/or modification for months. Level 2 facilities shall meet the 180 days after startup operations/modifications registration requirement, but not the pre-construction requirement. Alternatives if TCEQ keeps the pre-construction and approval requirement: 1. Establish a "reasonable" timeframe to review the application for completeness, protectiveness and NAAQs compliance demonstration and a) notify the applicant in writing that the application is incomplete: or b) notify the applicant in writing of any deficiencies. 2. Establish a "reasonable" timeframe to allow the applicant the submittal of any additional information. 3. If the TCEQ fails to issue a notice of completeness/deficiency within the established timeframe from receipt of the application or receipt of additional information requested, the application shall be deemed complete and construction, modifications and operations may start."

TPA commented that, "The proposed PBR should be amended to account for situations where Level 2 requirements are unexpectedly triggered. Subsection (h)(2) of the proposed PBR provides that TCEQ approval must be sought and obtained prior to construction or implementation of changes for OGS meeting certain emission levels. Such a provision assumes that the quantity of emissions will always be known ahead of time. But there may be circumstances where that is not the case, and the terms of the proposed PBR should be amended to account for such circumstances. For example, an operator might encounter a different type of gas than was expected, putting the project unexpectedly into Level 2. The operator in that case would not have obtained pre-approval. It has been suggested that, in such an instance, the operator would need to shut in the well until approval under Level 2 could be obtained from the agency. Such a requirement, however, would be entirely unreasonable. Shutting in a producing well can cause a reduction in production. Producers would be severely damaged under any sort of a shut-in requirement, which would have a negative impact on State tax revenue and the budget. The better solution would be to create a transition period so that, if an operator unexpectedly encountered a different sort of mix such as discussed above, the operator would not have to simply stop production, but instead would be allowed to continue operations while also being given a certain amount of time within which to amend its permits to account for the new sort of gas, with no shut-in requirements. TPA further commented that If the pre-approval provision is kept in the rule, then at a minimum there should be a specific time limit by which the agency must act. TPA suggests that the rule provide that TCEQ have 45 days from the submission of a complete registration within which the agency must issue its approval or disapproval, and that if TCEQ does not act within that 45-day period, the registration shall be deemed approved once the 45-day period has expired. Regulated entities should not be put in the position of having their operations suspended indefinitely due simply to agency delay in acting on completed and submitted registrations."

The commission has considered this comment and has changed the rule. The 90- and 180-day registration deadlines are set with consideration to the time it typically takes for an operator to determine the production of a well or group of wells. The ePermits system also will provide an immediate confirmation of registration or certification if all parts of the PBR are met, so no delay is expected.

BP commented that, "Some of the other states have a presumptive BACT program that states if you meet these BACT requirements for your equipment, you can submit an application after the construction of your facility. One of the reasons for requiring pre-construction authorization for an OGS over 10 TPY of VOCs was so that TCEQ can confirm the protection of public health - see Wyoming BACT Power Point presentation. Would a option for post-construction authorization if facilities control emissions over certain thresholds be adequate for demonstrating protection of public health in your opinion? Based on the health impacts review that you have done, perhaps if emissions on a facility are controlled in exceedance of a certain level, post-construction authorization could be used."

The commission has not changed the rule in response to this comment. Staff has reviewed Wyoming and Colorado regulations as a part of the background evaluation for the proposal. It is important to note that both states have very distinctive areas of oil and gas exploration and production, concentrated in the Basins and areas identified above. In both states there is little additional oil and gas activity in the remaining portions of the state. Additionally Colorado's rules require each piece of equipment (facility) to meet prescribed control requirements and obtain individual authorizations. Wyoming's rules also depend on "presumptive" BACT controls to authorize facilities by a streamlined mechanism. Neither of these approaches is recommended for Texas' PBR, instead controls are optional and choices that operators may make to reduce or eliminate emissions, but best management practices are minimum requirements.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that the "TCEQ should not penalize the operator for underestimating production but provide an opportunity to companies to update the emissions without penalty or allow for 6 months to demonstrate emission are below the authorization thresholds due to the rapid decline of well production. Also, the TCEQ should allow for a short initial notice of intent of an application to be submitted prior to the construction followed by a full application within 90 days of completion of construction. The initial short notice of intent of an application could include: The estimated production of gas and condensate or oil. The estimated pressure of the well; The equipment types and sizes that will be installed; A representative gas analysis if not drilling in a new field or formation; Location information; Distance to receptors and fence line."

The commission has changed the rule in response to this comment. The representative analysis, representative gas and liquid analysis will be accepted for registration purposes if they meet the criteria defined in the preamble. The Regional office may at any time request a site-specific gas and liquid analysis, as is part of their requirements.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Registration and authorization for the construction of a new facility is required prior beginning construction of the new facilities. If the production equipment cannot be constructed till authorization is received there is no way to get site specific gas and liquid analysis for the application. Representative analysis will have to be acceptable."

The commission has changed the rule in response to this comment. Representative gas and liquid analysis will be accepted for registration purposes if they meet the criteria defined in the preamble. The Regional office may at any time request a site-specific gas and liquid analysis, as is part of their requirements.

TPA commented that, "The proposed PBR should be revised in order to avoid conflict with the proposed circumvention rule. Under subsection (h)(4)(D) of the proposed PBR, if a facility is registered under Level 2 preconstruction registration, emission estimates must be updated within 180 days from the start of operation or implemented changes. The data may indicate that emissions are no longer under the PBR limit, meaning that the facility would have to register under a different permit. Yet TCEQ's proposed circumvention rule (30 TAC §116.110(h)) states that if a facility is authorized by a PBR, the agency will not accept an application for authorization of the facility under an NSR permit for a period of 12 months from the date on which the PBR was claimed or registered. This consequence needs to be addressed in the PBR."

TXOGA, Devon, GPA, Noble, ExxonMobil, Anadarko commented that the "rule should not penalize the operator for underestimating production but provide an opportunity to companies to update the emissions without penalty or allow for 6 months to demonstrate emission are below the authorization thresholds due to the rapid decline of well production. Also, new fees should not be required to update the applications."

The commission has changed the rule in response to this comment by adding subsection (f)(9) to allow for a limited time during which a company can change a notification intent to a different level of the PBR or standard permit while maintaining compliance.

Sierra Club and 2 Individuals commented that, "We would like to see the proposed electronic ePermit registration system for regulated entities be made publicly accessible."

The STEERS website does not have the compatibility to be accessible by the public. The public will be able to access the applications by using the Air Permits Remote Document Server or by calling the Air Permits Division.

Level 1

EDF commented that the general requirements for Level 1 be revised to read: "Planned downtime of any capture, recovery, or control device must be considered when evaluating emission limitations of this section, and (if needed) to the maximum extent practicable, gas streams shall be redirected to another control or recovery device during downtime."

The commission has not changed the rule in response to this comment. As with other operational scenarios covered under this PBR, control requirements are not stipulated, only options, if emissions cannot meet standards, guidelines, and limits.

TPA would also point out that subsection (g)(1)" is written in a confusing manner. Subsection (g)(1) provides that total maximum estimated emissions shall meet "the most stringent of the following." Normally, such an introductory provision would be followed by a series of different provisions, the "most stringent" of which would have to be met. However, what currently follows that introductory provision is but a single provision, subparagraph (A). This language should be rewritten to clearly identify the various choices that must be considered in the process of identifying the one requirement that is "most stringent" and that therefore must be met."

The commission has changed the rule in response to this comment. The commission agrees with this comment and has reorganized subsection (g) to consolidate all emission limits. In addition, the commission has consolidated Level 1 into a single set of limitations for clarity and based on comments.

TPA commented that, "Subsection (b)(5)(B) of the proposed PBR indicates that the provisions of subsection (g) are not applicable to existing facilities that are not changing the character or increasing the quantity of emissions. However, subsection (g)(1) and (2) are inconsistent with subsection (b)(5)(B), because subsection (g)(1) and (2), as they are currently written, would in fact apply new PBR limits even to existing facilities when those existing facilities are part of a project. TPA proposes that subsection (g)(1) and (2) be rewritten to remove this inconsistency. We suggest revising subsection (g)(1) to read: "Total maximum estimated emissions for the project shall meet the most stringent of the following," and we suggest that subsection (g)(2) be revised to read: "If a project meets the following, the facilities must be registered . . .." Tying the requirements of subsection (g)(1) and (2) to facilities within a project would make the language consistent with the agency's stated intention that " "{o}il and gas facilities currently authorized under a PBR and that remain unmodified are not affected by this proposal except for identifying notification and planned MSS." Subsection (b)(5)(B) of the proposed PBR indicates that the provisions of subsection (g) are not applicable to existing facilities that are not changing the character or increasing the quantity of emissions. However, subsection (g)(1) and (2) are inconsistent with subsection (b)(5)(B), because subsection (g)(1) and (2), as they are currently written, would in fact apply new PBR limits even to existing facilities when those existing facilities are part of a project. TPA proposes that subsection (g)(1) and (2) be rewritten to remove this inconsistency. We suggest revising subsection (g)(1) to read: "Total maximum estimated emissions for the project shall meet the most stringent of the following," and we suggest that subsection (g)(2) be revised to read: "If an OGS a project meets the following, the facilities must be registered . . .." Tying the requirements of subsection (g)(1) and (2) to facilities within a project would make the language consistent with the agency's stated intention that "{o}il and gas facilities currently authorized under a PBR and that remain unmodified are not affected by this proposal except for identifying notification and planned MSS" (TCEQ Interoffice Memorandum, from Richard Hyde to Commissioners, dated July 9, 2010, at 2)."

The commission has not changed the rule in response to this comment. To ensure that the single PBR registered for a group of operationally dependent facilities, or changes to such facilities, are appropriately evaluated and registered the commission has established that the various PBR level limits are based not only on the specific project, but all facilities which are included in the registration.

Senator Davis commented that, "Ethylbenzene is missing from the list of substances (benzene, xylene, toulene) requiring monitoring for compliance with hourly and annual ESL for receptors within 2700 feet. Hourly and annual emissions shall be limited based on the most stringent of subsections (h) or (k) of this standard permit. Compliance with ambient air standards shall be demonstrated for any property-line within 2,700 feet of a project under this standard permit for the following air contaminants: nitrogen oxides (NO_X), sulfur dioxide (SO_2), and hydrogen sulfide (H_2S) unless otherwise listed in subsection (k). Compliance with hourly and annual effects screening levels (ESL) for BTEX shall be demonstrated at the nearest receptor within 2,700 feet of a project under this standard permit unless otherwise listed in subsection (k)."

The commission has not changed the rule in response to this comment. Based on the updated emission impacts evaluation, it was determined that of all specific VOCs, benzene was the most critical to evaluate. The PBR requires hourly and

annual benzene impacts evaluation, as well as evaluations for NO_X, SO_2, and H_2S.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Process vents and blowdowns limits based on 30-foot process vent at a distance of 1400 feet. Tanks and truck loading limits based on a 20-foot tank at a distance of 1,400 feet. Purging limit based on 10ft stack at a distance of 1400 feet. VOC emissions based on a calculated Condensate Vapor Space ESL based on the TCEQ liquid speciation used in their Interim condensate ESL determination. (A)(ii) 3.1 lb/hr toluene; hourly toluene emissions for process vents/blowdowns of 10 lb/hr and tanks/truck loading emissions of 4 lb/hr; (A)(i) 0.8 lb/hr and 1.2 tpy benzene; Total site-wide benzene emissions of 1.2 tpy and hourly emissions for process vents/blowdowns of 3 lb/hr and tanks/truck loading emissions of 1.0 lb/hr. (g) Level 1 post-construction registration. (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."

Devon commented that, "(g) Level 1 Post-Construction Registration; (h) Level 2 Pre-Construction Registration(g)(2)(A), (g)(3)(A), and (h)(2)(A) and the hourly VOC emission limits stipulated in all three PBR levels are based on the effects screening level (ESL) of condensate, which assumes a speciated benzene content used to determine the VOC hourly limits, and is an inappropriate means of setting hourly VOC limits. Since protectiveness must be demonstrated for certain hazardous air pollutants (HAP), such as benzene and toluene, an hourly VOC limit based on HAP content of condensate is redundant, unnecessary, and unwarranted. Devon strongly believes that hourly VOC limits are redundant to demonstrating benzene protectiveness and should therefore be dropped from the PBR levels because such redundant requirements are costly and unreasonable. Annual VOC limits are appropriate based on VOC being an ozone precursor. In the event hourly VOC limits remain in the PBR, a more appropriate calculation basis should be applied using the ESL of natural gas to derive the hourly VOC limits. This is a justified approach because natural gas, not condensate, is vented during activities at OGS, such as during MSS events and well venting. Devon would also like to point to measured data collected from over 30-sites across different regions of Texas taken from the 2009 Hy-Bon tank study indicate an average benzene content of approximately 0.25 percent by weight in the storage tank oil, which is the location with the highest benzene content. The benzene content of the produced gas averaged 0.042 percent by weight using the data from the Hy-Bon study."

The commission has changed the rule in response to this and similar comments. All steady-state VOC emission limits for Level 1 are based on a distance of approximately 1/4 mile. While the commenter advocates the use of a 30-foot release height for process vents, the commission has determined this value to not reasonably conservative and instead used a 20-foot stack height from the two highest contributing steady-state sources. The commission has not changed the rule based on the speciation presented by the commenters as any change in ESL must proceed through the official process as published on the commission's website at *http://www.tceq.state.tx.us/implementation/tox/esl/peer_rev*. Periodic releases from truck loading, blowdowns, and downtime of flash emissions control systems typically release from either 20-foot tank vents or 10-foot piping valves. To be reasonably conservative, the commission used the 10-

foot release and established a resulting 145 lb/hr for a limited number of hours per year (frequency based on commenters statements and previously reviewed registrations).). For high-pressure releases, the commission has also added periodic limits based on a 10-foot release with corresponding limits for condensate, crude oil, natural gas, benzene and H_2S. Finally, the commission has deleted "well completion" from the actions which trigger registration as this term is not clearly defined and has multiple meanings.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Flare limit based on 40ft stack at a distance of 1400 feet." is the most appropriate dispersion characteristic for SO_2 limits.

The commission has changed the rule in response to this and similar comments. The commission has relied on larger engine stacks as the most typical and culpable source of SO_2 at an OGS, resulting in Level 1 limit of 47 lb/hr, Level 2, 63 lb/hr, and periodic releases of 93 lb/hr.

PBPA commented that, "The proposed annual SO_2 limit of 15 tons/yr will greatly increase the number of facilities required to comply with the standard permitting process. These companies are presently covered by the existing TCEQ Permit by Rule."

The commission has changed the rule in response to this comment. The

commission has revised the values for SO_2 based on the NAAQS, and the annual limit is almost 25 tpy, thus the commenters concern is resolved.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Hourly limits be based on a 20-foot engine (>1,000 hp) at a distance of 1400 feet: 2.0 lb/hr formaldehyde; 26 lb/hr (engine), 9 lb/hr (flare), and 10 tpy SO_2; 25 lb/hr (engine), 8 lb/hr (flare) and 25 tpy NO_X."

The commission has changed the rule in response to this and similar comments. All steady-state products of combustion emission limits for Level 1 are based on a distance of approximately 1/4 mile. After a more detailed review of various engine types, a common, typical engine with an 18-foot stack and 1,250 hp was chosen for dispersion characteristics.

Old Town Neighborhood Association commented that the commission should "Lower the PBR 25 ton VOC per year threshold to 25 pounds per year so that all pollution area sources are controlled as the nearby sites have aggregated emissions that are not regulated."

The commission has not changed the rule in response to this comment. The proposed emission limit of 25 lb/hr of VOC is not a realistic limit for the facilities in the oil and gas industry, nor is it necessary to ensure protectiveness.

Representative Burnam suggests that VOC emission be limited to 5 and 10 tons per year respectively in ozone nonattainment counties for PBR Level 1 and Level 2. This would leave the proposed incentive structure in place for all other counties but would ensure lower VOC emissions in nonattainment areas. As an alternative, eliminate the Level 2 PBR registration in ozone nonattainment areas and limit the VOC emission limit under the standard permit to 10 tpy. This means that applicants in nonattainment areas who limit their VOC emissions to 10 tpy would be eligible for a PBR. Otherwise, they must obtain a standard permit. Applicants outside the nonattainment areas would retain the three options, Level 1 and 2 PBR or the standard permit.

The commission has not changed the rule in response to this comment. Additional controls in nonattainment areas are driven by state implementation plan requirements in 30 TAC Chapters 115 and 117 and adding the various thresholds proposed would add unnecessary complexity to the PBR.

Senator Davis stated the "key to responsible drilling in Barnett Shale is increased monitoring, enforcement and open communication with the public. We must have reliable, trustworthy and transparent data to ensure that the state of Texas is protecting the health and safety of our families living in the midst of gas drilling."

The commission has changed the rule in response to this comment. The commission agrees with the comment and is adopting PBR requirements which require notification prior to construction or changes, registration with detailed information within a short period of time, and comprehensive practically

enforceable sampling, monitoring, and record requirements.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Proposed §106.352(h) refers to "Level 1 Notification." The use of that term is confusing because it is used nowhere else in proposed §106.352. That term appears to be referring to the term "Level 1 post-construction registration", which is used in proposed §106.352(g) of the Proposed PBR. If that is the case, TXOGA requests that §106.352(h) be revised to read as indicated in the column to the right. Level 2 Preconstruction Registration. If the requirements of the Level 1 post-construction registration in subsection (g) Notification cannot be met, then the conditions of this subsection must be followed.""

The commission has changed the rule in response to this comment. The commission has added language in subsection (f) to clarify what is expected for a notification and registration under this PBR.

Earthworks Texas Oil and Gas Accountability Project commented that, "Rule should be practically enforceable and not allow circumvention of federal standards."

The commission appreciates the comment and has spent hundreds of man-hours on this rule project to ensure a practically enforceable authorization and complies with all federal standards.

ConocoPhillips commented that, "The revised PBR appears to provide some unnecessary complexity which may render it overly burdensome to implement. In general, a PBR is supposed to be among the simplest type of New Source Review ("NSR") permits. Minor source NSR, Major source PSD, and Nonattainment permits are all expected to be more intricate and involved than a PBR. However, there are aspects of this PBR that rival the intricate and onerous requirements of the necessarily more complex permits because these permits are for more complex and larger sources."

The commission has changed the rule in response to this comment. The commission appreciates the comment and has reorganized various portions of the PBR to streamline and clarify requirements.

TPA commented that, "The proposed PBR contains various levels (Level 1 / Tier 1, Level 1 / Tier 2, and Level 2) that would apply to a site based on the site's lb/hr emission levels. TPA urges TCEQ to eliminate this multi-level structure altogether, for two reasons. First, because dividing the PBR into multiple levels only adds confusion and complexity to the rule; and second, because the threshold hourly limits that would trigger application of the various levels are inappropriate in a PBR."

The commission has revised the rule in response to this comment and has consolidated the 2-part system of Level 1registration.

Certification

ETC stated with regard to the proposed revisions to subsection (b)(5)(B), "ETC notes that it would not be appropriate to refer only to "certified" emissions because not every facility has certified emissions. For this reason we propose deleting the term "certified" in that subsection. ETC recommended (B) Notwithstanding any other provision in this section, existing authorized facilities, or group of facilities, at an OGS under this section which are not changing the certified character or increasing the quantity of emissions must only meet paragraph (6) of this subsection and subsection (i) of this section."

The commission has not changed the rule in response to this comment. If certified limitations are not specified in the PBR, then any change with a potential to increase emissions for an existing PBR or Standard Exemption would trigger all new rule requirements and this is inconsistent with the established authorization scope for all registered or claimed facilities.

EDF stated they are concerned that "the condition about changes to existing facilities which increase emissions to "amounts greater than previously certified" may be meaningless for sweet gas facilities that may never have registered with the commission. The TCEQ should add clarifying language that the requirements apply whether or not registration or certification ever occurred. Where no prior certification of emissions exist, the TCEQ should require re-registration if actual emissions ever exceed those in the highest year out of the last 5 years."

The commission has not changed the rule in response to this comment. It is long-standing practice and the intent of the general requirements of all PBRs that

representations do not limit facilities, only the limits of a particular PBR or a self-imposed certification.

Pioneer requested for the commission to "please clarify "increase emissions to amounts greater than previously certified." Does this mean emissions over PBR limits, emissions in the record keeping estimate, only emissions estimates submitted to the TUC), or only emissions certified under a PI-7-CERT? What if the PBR was not registered with the TCEQ or certified? This issue must be clarified in the regulations."

The commission has used the term "certified" very specifically as it refers to §106.6. Certifications only those PBR claims where the operator has voluntarily filed paperwork (via PI-8, PI-7-CERT, or APD-CERT) to clearly establish federally enforceable limitations on facilities.

EDF stated "since previously authorized OGS in sweet gas service did not have certified representations of emissions, language should be added to require registration of such OGS if historical emissions are exceeded, for example the highest year out of the most recent rolling 5-year period."

The commission did not revise the rule wording in response to this comment. Under existing general requirements for PBRs, representations of non-certified claims are not binding, only the limitations of the rule.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Certification (APD-CERT or PI-7-CERT) of emissions is not need if the potential is less than §106.4 emission limits and are routine."

The commission respectfully disagrees with this comment and has not changed the rule. Certification of PBRs is required in a wide variety of circumstances, including those outlined in §106.6, commission PTE guidance, and published EPA guidance. The most common circumstances at oil and gas facilities are included in the rule.

EDF commented that, "Since truck loading emissions can be significant, the TCEQ should require a certification that only submerged loading will be utilized, or alternatively a certification of the truck loading method to be employed at the site and a justification for the resulting emissions."

The commission has not changed the rule in response to this comment. While submerged loading is preferred and can reduce vapor losses it may not be available to some small old operations or may be impractical for unique technical reasons, so it is not being mandated unless necessary to meet emission limitations of the rule.

C. Technical Issues

The Old Town Neighborhood Association expressed concerns that "the risk of ground water contamination has grown exponentially in recent years due to over 265 percent growth in natural gas drilling. When combining that risk with the relatively new horizontal fracturing technology, that further increases the risk because horizontal fracturing can reach more subsurface footprint by around 6,400 percent than the traditional vertical drilling. They recommended that all hydraulic fracturing should be permitted only with ground water monitoring wells nearby that test the water during the life of the well."

The commission has not changed the PBR or standard permit in response to this comment. The scope of authority for air authorizations is limited by THSC, Chapter 382, and does not cover ground water issues, drilling or hydraulic fracturing.

Two individuals stated that companies should be required to submit baseline tests before any exploration takes place. "Our County Groundwater District does not have the authority to monitor the drilling of water well nor the amount of water being used by the Oil and Gas Industry. As landowners, we do not know what chemicals are being injected into our groundwater either. We also do not have any idea what particles are in our air due to a nearby Coal Plant and the Oil and Gas production in our area. I welcome more information and action on the part of TCEQ to regulate these industries."

The commission has not changed the PBR or standard permit in response to this comment. The scope of authority for air authorizations is limited by THSC, Chapter 382 to stationary sources of air contaminants and does not cover petroleum exploration, drilling, hydraulic fracturing, or any ground water issues.

In addition, the concerns expressed about particulate matter from a coal plant, which is beyond the scope of this action. The commission has reviewed potential particulate matter from oil and gas production facilities as a part of this action and finds that the sources of PM_{10} and $PM_{2.5}$ within the scope of this project are exclusively from products of combustion from engines, heaters, boilers, and flares. A detailed evaluation of these potential PM emissions is covered in the background justification and section by section discussion.

One individual commented "In terms of quality, the Clean Water Act was made into law before the fracking process was developed. Therefore, the chemicals used in the process are not regulated, so these companies are not required to identify the chemicals they mix with the water in the process. Yet, some of these chemicals are known to be toxic or carcinogenic. It is the responsibility of the TCEQ to be vigilant in preserving and protecting the water resources of Texans. With regard to the chemicals used, even if the Congress has not yet enacted legislation to bring the fracking process and their chemical identification in line with the standards of the Clean Water Act, TCEQ still has a responsibility to require that these companies identify the chemicals they intend to use in their fracking operations."

The commission has not changed the PBR or standard permit in response to this comment. The scope of authority for air authorizations is limited by THSC, Chapter 382, and does not cover ground water issues, drilling or hydraulic fracturing and these issues are beyond the scope of this project.

EDF stated, "We support the specification of geologic formations to ensure that landfill gas facilities would not be authorized under this section. Since impurities in landfill gas may be expected to differ in composition from gases associated with traditional (geologic) oil and gas production facilities, the former should be authorized under a separate mechanism."

The commission appreciates the support and agrees with the commenter that landfill gas with compositional impurities that are different or inconsistent with traditional (geologic) oil and gas materials are not included under the PBR.

Senator Wendy Davis requested that "subsection (a)(3) should be modified to include a reference to state or federal laws. By including "laws," legal rules beyond the administrative level are included such as ordinances, statutes, and case law."

The commission changed the rule in response to this comment and agrees that this change further emphasizes that comprehensive compliance is expected from any business in Texas.

El Paso requested that "subsection (a)(4) be revised to clarify that excess emissions due to upsets and malfunctions are not authorized by this section. An upset or malfunction that does not result in emissions exceeding any hourly or annual limitation should not be considered "unauthorized" if they do not exceed an applicable emission limitation. Please consider the following: Emissions from upset or malfunctions are not authorized by this section where such, emissions exceed the hourly or annual /imitations set forth in this section."

The commission respectfully disagrees with this comment and has not changed the

rule. Regardless of the quantity of emissions, unplanned emission releases are not ever intended to be authorized but instead in all cases must meet the requirements of 30 TAC Chapter 101.

Pioneer questioned subsection (a)(4) and asked "Does this mean that OGS or facilities that emit methane, ethane or CO_2 cannot be registered under the proposed §106.352? This language is confusing and should be deleted since federal regulations are in place under the Clean Air Act (ie: PSD Tailoring Rule) to regulate greenhouse gases."

The commission respectfully declines to change the rule in response to this comment. The last sentence of subsection (a)(4) was added after numerous comments were received after the Stakeholder's Meeting held in April 2010. This statement ensures that all parties understand that greenhouse gases (GHG) have not been evaluated for emissions, controls, monitoring or records requirements under this PBR. When the Texas legislature passes laws to address permitting of GHG, this PBR will be updated accordingly.

EDF commented that, "The allowance for a 100 hp engine should be removed, and such an addition should count toward the total emissions increase permitted in this subsection."

The commission has not changed the rule in response to this comment. A 100 hp engine would emit at very low levels. Specifically mentioning the 100 hp engine allows an easier method of determining if a change must be registered.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA further discuss that "any compressor or heated vessel operating at an OGS will have nitrogen oxides and other combustion-related emissions. Thus, based on the generally simple production operations at a typical OGS and as explained in more detail in these comments, a PBR or standard permit is the appropriate mechanism to authorize air emissions at an OGS. TXOGA contends, however, that these relatively simple operations do not merit the degree of regulation that would result from the Proposed Rules. In fact, as OGS are comprised of a series of fugitive emission sources and are subject to federal New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPs") just as other similar fugitive emission sources are under the TCEQ rules, TXOGA questions the need to subject OGS to more stringent requirements at this time. It is TXOGA's understanding that the federal NSPS and NESHAPs, are currently under review by EPA and are likely to be revised soon to impose more stringent requirements on OGS. TCEQ should wait to see what changes will be made at the federal level so that potentially inconsistent requirements are not imposed at the state level that will place Texas operators at an economic disadvantage relative to similar operations in other states."

The commission respectfully disagrees with several statements regarding potential emissions, such as "Low levels of VOC emissions may be detected from storage tank vents, hatches and pressure relief devices", " Glycol dehydrators can also have low levels of VOC emissions", and "VOC emissions may also come from minor leaks in various valves and piping connections." Based on several years of inspections and studies, all of these sources have been shown to often have a large quantity of potential emissions if not properly maintained or controlled. The commission does recognize the description provided includes controls of these

sources, such as "vapor recovery units or a flare" and "condenser or flare," but it is not uncommon for the commission to observe facilities with no, or improperly operating, controls. To ensure that all authorized facilities are appropriately controlled or at least emissions are protective, the new rules require an accurate accounting of all potential sources that all controls are properly designed and operated, and practically enforceable records are maintained to demonstrate compliance, thus ensuring insignificant emissions.

NorTex "particularly appreciates and supports the change made to the proposed standard permit to include facilities associated with depleted field storage of dry natural gas under the standard permit. This type of storage provides a critical link in the natural gas production, transportation and distribution system, allowing utilities and other consumers to hedge against shortages and high prices. Inclusion in the standard permit is essential to making that needed storage capacity readily available. As we noted in our informal comments, inclusion of dry natural gas storage also makes sense from a regulatory perspective. The character and nature of emissions at a storage facility are virtually identical to those at production and other storage sites, as are the type of equipment seen under the standard permit. Emissions associated with underground storage of dry natural gas generally include NO_X, VOC, PM, CO and benzene, but emission rates tend to be lower due to the fact that pipeline quality gas is being managed. Equipment associated with underground storage is generally comprised of engines, glycol reboilers, heaters, heater treaters, amine units, tanks, fugitives, and loading and unloading emissions. The emissions from the underground storage alone are *de minimis* in comparison to emissions from these common types of equipment. As noted in the preamble, risks of at underground storage facilities may actually be less than for other upstream or downstream oil and gas facilities due to stringent measures adopted by the Texas Railroad Commission to prevent these hazards. Railroad Commission safety regulations for underground storage are regularly upgraded, including a revision in January 2007. Current requirements include standards for leak detection, integrity testing, training, monitoring and emergency response. Given the specific scrutiny and oversight of the facilities under the Railroad Commission, these facilities do not present a unique risk sufficient to disqualify them from use of the standard permit."

The commission agrees with the commenter and concurs that dry natural gas storage has the same character and quantity of emission from other oil and gas facilities and it is appropriate to include them in this PBR and standard permit in subsection (d)(1)(I).

TXOGA, Anadarko, Noble, ExxonMobil, and GPA submitted Exhibit 2, "a diagram that depicts a typical OGS. A typical oil and gas production facility has a wellhead which is basically an assemblage of valves and meters over the subsurface well casing and tubing which conveys oil, natural gas and produced water to the surface. Exhibit 2 demonstrates that the gas and liquids from the wellhead (described as "Oil/Gas" in Exhibit 2) enter the wellhead assembly and are typically piped to a line heater (if the well is a gas well) and then to one or more separators. The lower pressures and temperatures in a separator allow natural gas, oil and produced water to naturally separate with gas coming out of solution from crude oil and natural gas liquids condensing ("condensate") and separating from natural gas. For oil wells, the liquids in the separator may be routed to a heater treater to facilitate additional oil-water separation. Crude oil, condensate and produced water are routed from the separator (or heater treater if one is used) by flowline to storage tanks (as depicted in Exhibit 2). Generally crude oil and condensate are then sold and trucked away from the storage tanks by a third-party buyer. Produced water is trucked or piped to a produced water disposal well. Natural gas may be routed from the separator (or separators) to a glycol dehydrator. Gas passes through a column containing glycol which removes any residual water in the gas and the gas is then routed by flowline into a gas pipeline for sale or a gas gathering system for further processing at a gas plant. Depending on the pressure in the gas pipeline or gathering system, a compressor may be used to force the produced natural gas into the gas pipeline or gathering system. Additional facilities that may be found at an OGS include an amine unit to remove CO_2 if that is present in the natural gas and, as mentioned previously, a heater treater to break a crude oil-produced water emulsion that can result from pumping an oil well. A flare may also be present at an OGS to flare natural gas in the event, for example, of an equipment malfunction or maintenance shutdown of a third-party gas plant. Emission sources at an oil and gas production facility are likewise limited by the type and amount of equipment at the facility. Low levels of VOC emissions may be detected from storage tank vents, hatches and pressure relief devices. These are often controlled by vapor recovery units or a flare. Glycol dehydrators can also have low levels of VOC emissions and these emissions are typically controlled by routing them to a condenser or flare. VOC emissions may also come from minor leaks in various valves and piping connections."

The commission appreciates the information on various typical facilities and operations used in the oil and gas industry in Texas. Recognizing the variability of equipment configurations and materials processed, the revised rules account for

all types of these facilities. However, the commission respectfully disagrees with several statements regarding potential emissions, such as "Low levels of VOC emissions may be detected from storage tank vents, hatches and pressure relief devices", " Glycol dehydrators can also have low levels of VOC emissions", and "VOC emissions may also come from minor leaks in various valves and piping connections." Based on several years of inspections and studies, all of these sources have been shown to often have a large quantity of potential emissions if not properly maintained or controlled. The commission does recognize the description provided includes controls of these sources, such as "vapor recovery units or a flare" and "condenser or flare", but it is not uncommon for the commission to observe facilities with no, or improperly operating, controls. To ensure that all authorized facilities are appropriately controlled or at least emissions are protective, the new rules require an accurate accounting of all potential sources, that all controls are properly designed and operated, and practically enforceable records are maintained to demonstrate compliance.

EDF recommended "To avoid any future disputes, we suggest including a definition of "fugitive components" or "fugitive emissions" One potential definition of fugitives could be drawn from EPA's Mandatory Reporting Rule for Greenhouse Gases: "Fugitive emissions means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening." 40 CFR Part 98.6, EPA Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems; Proposed Rule, (75 Fed Reg 18608, 18634)."

"Fugitive Emissions" are currently defined in the Air General Rules at §101.1(39) in the same manner as suggested with the additional definition of "Component" at §101.1(18). These definitions are legally applicable to this rule. The definitions provide a basis that has been in place and has not been problematic in the past. To further clarify intent and assure appropriate consistent emission accounting calculation assistance tools are being developed and included in outreach that talk to specific components and proper estimation.

TAEP stated "A separator is a separator is a separator; they are not uniquely different. The same is true of 219 barrel tanks."

The commission wants to be clear, all variety of separation in oil and gas production is included. There are a large variety of separation processes at OGS that are all allowed authorization under this rule. They can be totally enclosed with no emissions, or pressurized and venting to atmosphere with substantive emissions. The commission has moved away from the list of specific types, "gun barrels, free-water knockouts, oil/water, and membrane units" to clarify other types or names of simple physical property separation is allowed to be authorized by the PBR.

EPA commented that subsection (d)(1)(E) states, "that iron sponge units are allowed under the standard permit and PBR. Has TCEQ considered a restriction on the size allowed?"

The commission has not considered limiting the size of an iron sponge, we have focused on establishing protective emission limitations and expect the industry to apply the appropriately sized and type of unit to the task.

Cirrus Environmental stated "There are no standards in Table 9 of the proposed PBR for dual-fuel or diesel engines as there are in the current PBR. Section 106.352(d)(1)(H) states that engines may be registered using the PBR and §106.352(e)(4)(C) states that diesel engines used for backup and periodic power are authorized for up to 500 hours per year as long as they meet the fuel sulfur requirement. What about other diesel and dual-fuel engines? Are they authorized by the new PBR? If they are authorized, please clarify what emission standards apply. If they are not authorized, please clarify why they are not and how they should be authorized."

The commission has added dual-fuel engines to Table 6 in subsection (m). Non-emergency diesel engines have been added to subsection (e)(4).

ETC commented that, "Many of the control requirements prescribed in the proposed rule attempt to establish presumptive BACT and are the sort of requirements that are developed through the case-by-case NSR permit process. While a Standard Permit must incorporate BACT requirements, it is clear that the Texas Clean Air Act does not require BACT for facilities authorized by a PBR. The omission of a requirement for BACT in the statutory authority for PBRs, together with a number of written statements by TCEQ staff, support the conclusion that BACT is not required for PBR authorized facilities. This is consistent with the policies underlying PBRs, which seek to minimize regulatory and economic burdens for insignificant sources of emissions. By requiring BACT control requirements in the Oil & Gas Sites PBR, TCEQ is attempting to establish "presumptive BACT" for the Texas oil and gas industry during a PBR rule development. The establishment of presumptive BACT should not be arbitrarily prescribed in a draft proposed rule for PBRs. Rather, this process should be subject to a comprehensive cost/benefit analysis and undergo a separate stakeholder/public hearing process."

The commission agrees with portions of this comment and has clarified the rule to make it clear that most control technologies are completely voluntary. The emission limitations, primarily for engines, are less than BACT and do not require upgrades until after the typical life cycle of catalysts or entire engines. The commission did complete, and publish, a comprehensive control cost/benefit analysis in this rule proposal package and has made additional changes based on stakeholders comments to engine requirements.

TPA commented that, "Another major flaw in the PBR is that it would prescribe a host of detailed control and operating requirements. TPA believes that such prescriptive requirements are unnecessary and have no place in a PBR. If a site meets the overall emissions limits requirements set forth in the PBR, then that is all that should matter; the particular means by which the site is able to meet those limits is irrelevant to the environment and it should be irrelevant to the TCEQ. The inclusion in the PBR of numerous pages of detailed control requirements would inject unnecessary confusion and complication and would make it harder for the regulated community to determine whether or not a PBR could be claimed."

The commission respectfully disagrees with the commenter. Due to the high potential emissions from oil and gas facilities, any control device or system which is relied upon for reductions is of great interest for design, operations, effectiveness, and continuing good operations. The requirements of the PBR focus on these areas to ensure practically enforceable mechanisms for control of emissions to the atmosphere.

Old Town Neighborhood Association stated that "aged equipment on OGS should be subject to revocation of their permit until replaced with the most current best available technology."

The commission has addressed requiring the use of updated technology and BACT as much as possible. Based on current rules, except for PBR §106.496 for air curtain incinerators which require renewal of registrations every 5 years, registrations or claims under PBRs are valid until changes are made under PBRs. If changes are made, the requirements of currently effective PBRs must be met. standard permit registrations must be renewed every 10 years and must meet BACT at the time of renewal. Time allowances were made in the new OGS rules for phasing in new requirements. Some existing OGS facilities need to comply with current federal rules requirements, and some existing OGS facilities will have to comply with pending, future federal rules requirements. Additionally, the commission cannot be presumptive by applying all the new OGS rules to existing

facilities.

Fasken commented that they had "seen the cost estimates provided by the Permian Basin Petroleum Association to install smokeless combustors on flares, purchase and operate vapor recovery units, and paint tank batteries in reflective colors. Fasken believes the potential costs associated with these proposals would be an economic hardship for many independent operators. Fasken disagrees with TCEQ's analysis that there would be no significant economic effect and states that TCEQ needs to perform an economic analysis as required by Texas Government Code, 2001.0225. Fasken is concerned about the immediacy of the implementation of these regulations and that all operators will be scrambling to purchase equipment and get facilities into compliance, adding to the economic hardship. Fasken believes that the heart of the proposal is dramatically lowered standards for VOCs, H_2S, and SO_2. No other gas producing state has limits this low. Fasken proposes that the regulation be withdrawn and a new coordinated effort between TCEQ and the industry begun. Input from the oil and gas community is critical to balanced regulation."

The PBR does not mandate control unless it is necessary to meet emission limitations of the rule. If an applicant can establish that their facilities and operation at their location are unique and should not need to meet the emission limitations of this rule they may apply for a case-by-case NSR permit.

EDF recommends "the following BMP: Plunger Lifts and "Smart" Well Automation during Well Unloading. Operators often remove unwanted fluids from mature gas wells through "well unloading"- practices that lead to venting of methane, HAPs and VOCs. One way to remove unwanted fluids without venting while also improving well productivity is to install a plunger lift system and "smart" well automation system. Plunger lifts use gas pressure buildup in the well casing-tubing annulus to operate a steel plunger that pushes liquids to the surface. Smart well automation maximizes the efficiency of plunger lifts by routinely varying plunger well cycles to match key reservoir performance indices. Natural Gas STAR partners have reported annual gas savings averaging 600 thousand cubic feet ("Mcf") per well and increased gas production of up to 18,250 Mcf per well, worth an estimated $127,750 through the implementation of plunger lifts. Installing smart well automation on plunger lift systems typically results in an average savings of 500,000 cubic feet of methane per well, per year."

The commission appreciates the information and will look into sharing the information in our Pollution Prevention outreach programs. The technology had not been evaluated by the TCEQ in sufficient detail, would expand the scope of the proposed rule and cannot be added in this rulemaking.

EDF recommends "the following BMP: Installation of BASO Valves on All Gas-fired Heaters. Crude oil heater-treaters, gas dehydrators and gas heaters located at exploration and development sites have pilot flames which can be extinguished by strong winds, causing the venting of natural gas. BASO valves automatically shut off the flow of natural gas upon the extinguishment of the pilot flame, thereby preventing unnecessary pollutant and methane losses. BASO valves are operated by a thermocouple that senses the pilot flame temperature and do not require electricity or manual operation. They are therefore ideal for remote locations. Capital costs are negligible, with each valve costing less than $100, and savings can be as great as 203 Mcf year for a 1,000 barrel per day heater-treater that experiences a flameout period of 10 days annually. Payback depends on how often the pilot flames go out and for what length of time. Typically payback occurs in less than 1 year. A clean air standard based on the installation of BASO valves could result in significant product savings and emission reductions."

The commission appreciates the information and will look into sharing the information in our Pollution Prevention outreach programs. The technology had not been evaluated by the commission in sufficient detail, would expand the scope of the proposed rule and cannot be added in this rulemaking. The proposed fugitive monitoring would require leaks which are observed from the compressor to be repaired or replaced. The commission appreciates this additional information and plans to research it for inclusion in a future update to this proposed rule. In addition, the situation described in the comment represents an unauthorized emission commonly called an upset.

EDF recommends "the following BMP: Replacing Compressor Rod Packing From Reciprocating Compressors. Reciprocating compressors are one of the largest sources of methane emissions at natural gas compressor stations. Methane emissions are produced by leaks in the piston rod packing systems used in the compressors—especially from older systems. Replacing compressor rod systems reduces methane emissions, increases savings, and results in greater operational efficiencies and equipment life-spans. Average gas savings equal $6,055 a year and far exceed the $540 implementation cost and the payback is 2 months. California has proposed installing compressor rod packing systems as one strategy for reducing emissions from the state's oil and natural gas transmission industry. This, along with other strategies such as improving operating practices when compressors are taken off-line and replacing old flanges and fittings along pipeline, are expected to yield 0.9 MMT CO_2 annually and save the oil and gas industry $17 million in annualized net savings."

The commission appreciates the information and will look into sharing the information in our Pollution Prevention outreach programs. The technology had not been evaluated by the commission in sufficient detail, would expand the scope of the proposed rule and cannot be added in this rulemaking. The proposed fugitive monitoring would require leaks which are observed from the compressor to be repaired or replaced.

EDF recommends "the following BMP: Replacement of Wet Seals with Dry Seals on Wet Seal Centrifugal Compressors. Centrifugal compressors are widely used throughout the natural gas production and transmission sectors. Seals on rotating shafts are used to prevent natural gas losses from compressor casing. Many of these seals use high-pressure oil as a barrier against escaping gas. These types of seals, referred to as "wet" seals, produce methane emissions when the circulating oil is stripped of the gas it absorbs. Dry seals use high-pressure natural gas instead of oil to prevent gas losses. They also have lower power requirements, improve compressor and pipeline operating efficiency and performance, enhance compressor reliability, and require significantly less maintenance. A dry seal can save about $315,000 per year and pay for itself in as little as 11 months. One Natural Gas STAR partner who installed a dry seal on an existing compressor reduced emissions by 97 percent, from 75 to 2 Mcf per day, saving almost $187,000 per year in gas alone."

The commission appreciates the information and will look into sharing the information in our Pollution Prevention outreach programs. The technology had not been evaluated by the commission in sufficient detail, would expand the scope of the proposed rule and cannot be added in this rulemaking. The proposed fugitive monitoring would require leaks which are observed from the compressor to be repaired or replaced.

EDF recommends "the following BMP: Leak Detection and Repair at Compressor Stations in the Transmission and Storage Sectors. Compressor stations occur throughout the natural gas transmission and storage sectors and act to compress the gas to varying pressure points to overcome pressure losses that occur along a long-distance pipeline. According to EPA, compressor stations in the transmission sector alone account for approximately 50.7 billion cubic feet (Bcf) of methane emissions annually. A leak detection and repair program, similar to that already required for equipment and compressors located at natural gas processing plants, see 40 CFR Part 60, Subpart KKK, offers a cost-effective way to prevent and eliminate emissions from compressor stations. Baseline surveys done by EPA partners have revealed that the majority of leaks come from a small number of parts, mostly valves, and that once these parts are identified, cost-effective repairs can be streamlined to accomplish maximum emissions reductions and gas savings."

The commission appreciates the information and will look into sharing the information in our Pollution Prevention outreach programs. The technology had not been evaluated by the commission in sufficient detail, would expand the scope of the proposed rule and cannot be added in this rulemaking. The proposed fugitive monitoring would require leaks which are observed from the compressor to be repaired or replaced.

Old Town Neighborhood Association stated that "aged equipment on OGS should be subject to revocation of their permit until replaced with the most current best available technology."

The commission has addressed requiring the use of updated technology and BACT as much as possible. Based on current rules, except for PBR §106.496 for air curtain incinerators which require renewal of registrations every 5 years, registrations or claims under PBRs are valid until changes are made under PBRs. If changes are made, the requirements of currently effective PBRs must be met. Standard permit registrations must be renewed every 10 years and must meet BACT at the time of renewal. Time allowances were made in the new OGS rules for phasing in new requirements. Some existing OGS facilities need to comply with current federal rules requirements, and some existing OGS facilities will have to comply with pending, future federal rules requirements. Additionally, the commission cannot be presumptive by applying all the new OGS rules to existing facilities.

TPA stated that "the only requirements for engines, glycol dehydrators, and tanks in ozone attainment areas should be that the facility complies with all applicable 40 CFR 60 NSPS, NESHAP, and MACT requirements. In less than 2 years, all engines will be subject to either existing or new engine 40 CFR 60 NSPS and/or MACT regulations. Minor source glycol dehydrator emissions were recently revised by EPA under the "residual risk" review requirements. In addition, EPA has agreed to review all major and minor source 40 CFR 60 NSPS and NESHAP regulations for the oil and gas sector and propose any changes within a year. Instead of adding an additional layer of duplicate requirements, the PBR should incorporate by reference the 40 CFR 60 NSPS and MACT standards (Part 60 and 63) and require facilities to comply with the applicable requirements in those standards."

The commission cannot set NSR permit standards based on the NAAQS attainment status of an area. The regulatory need for updating §106.352 is different than what the EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with a federal rule to also be used for state purposes and minimize any additional cost to industry.

ETC recommended rule changes to (B) "documentation of the engine's manufacture date and type (spark or compression ignition, lean or rich-burn), hp rating, the most recent EPA method test must be included in the registration."

The commission agrees and changed subsection (m), table 8 to include this

recommendation.

Exterran commented that, "Both the Proposed PBR §106.352 (e)(4)(B) and the Proposed Standard Permit subsection (f)(2)(B) require "any previous emission sampling results summary" to be included in the respective registration for each engine. Because of the relatively recent recordkeeping requirements on some engines historical tests may not always be available for engines transported to Texas from other states or obtained from other parties. Recommendation: This section should be amended to allow as an alternative reference method testing to be conducted upon startup and submitted within an acceptable timeframe when available."

The commission agrees and changed the proposed rule in response to this comment. A permit holder may test an engine upon initial startup at a site using EPA reference method testing in lieu of providing any previous sampling reports.

ETC recommended rule changes for subsection (e)(3)(A), "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 percent sulfur and is operated less than 500 hours per rolling 12-month period. Fuel for all other internal combustion engines used for back-up power generation and periodic power needs at the OGS 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."

The commission deleted this sentence in response to this and other comments.

Exterran commented on the sour gas requirement. "Currently, both the Proposed Standard Permit (Table 11) and the Proposed PBR (subsection (l), Table 8) requires the owner/operator to maintain records to demonstrate that the SO_2 emissions do not exceed certain levels. Exterran supports this requirement as proposed. In light of these operating requirements, additional engine restrictions proposed for certain sour gas operations are not necessary. For example both the Proposed Standard Permit (f)(2)(C) and Proposed PBR §106.352(e)(4)(C) state that, "Fuel for all other {non-diesel} ICE shall be sweet gas or liquid petroleum gas unless the engine is lean-burn and rated under 500 hp in which case sour gas is allowed." Exterran requests that this engine requirement is unnecessary due to the H_2S Requirements and Fuel Record requirement in the respective proposals. Additionally, although Exterran understands that TCEQ is referring to sour gas operations where only 2 SLB can operate at a field without the assistance of a gas treatment plant, the use of the term "sour gas" may unnecessarily restrict engines from fields where lower levels of H_2S may not prevent operations of other engine types. Recommendation: We request that TCEQ delete the engine restrictions in Proposed Standard Permit (f)(2)(C) and Proposed PBR §106.352(e)(4)(C) and instead continue to rely upon the operation and recordkeeping requirements for sour gas fields as provided in the Proposed Standard Permit (Table 11) and the Proposed PBR (Table 8) of subsection (m)."

After consideration, the commission added language the adopted OGS rules indicating that any natural gas can be used as fuel for engines. The commission is aware of how even slightly sour gas may damage some kinds of engines and

believes it is not in OGS best interest to use fuel that would destroy engines. Please note that impacts analysis for SO_2 or H_2S may be required if sour gas is used as fuel. The commission did not change sulfur content requirements for liquid fuels. For sour gas fields, the commission has addressed record requirements and confirmation of sulfur content in the portions of this rule package which address liquid and gas analysis and general record requirements.

ETC recommended changes to subsection (e)(3)(B), "engines and turbines used for electric generation more than 876 hours per rolling 12-month period are authorized if no appropriate electric grid access is immediately available 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) {no change}; (F) {moved to (A)}.")."

The commission has reworded this condition in response to the comment. However, the commission did not delete the requirement for the emission standard to be met in subsection (m), Table 6. A gas-fired engine to run a generator is not sufficiently different that one used to run a compressor that a potentially much higher emission rate is justified. In fact, the steady load of a generator would allow for potentially more controls to be applied to the unit which is why the EGU Standard Permit may be used for power needs longer than 876 hours at sites that do have access to the electric grid.

EPA commented that §116.620(f)(2)(D) and §106.352(e)(4)(D) " appears to allow the OGS to also claim the Electric Generating Unit standard permit. Are any other standard permits allowed to be claimed with the OGS standard permit or the PBR? Would those facilities authorized under a standard permit be included with the facilities covered by the OGS standard permit or PBR for determining site-wide emissions?"

Potentially, an OGS could also claim a Pollution Control Project Standard Permit. The intent of the language is that one would meet the EGU Standard Permit requirements but the EGU would be authorized under the OGS standard permit. In this regard, the EGU will be part of the site-wide emissions for the OGS standard permit. The proposed rule had been clarified in response to this comment.

Cirrus Environmental commented that, "RICE MACT (40 CFR Part 63, Subpart ZZZZ) requires semiannual testing of NO_X and CO using portable analyzers whereas the proposed rules require quarterly testing. Why do the proposed rules and other state regulations (e.g. 30 TAC Chapter 117) require quarterly testing when the MACT doesn't? Has the benefit of more frequent testing been quantified?"

Periodic monitoring was deleted in response to comments except that sites subject to Title V must follow periodic monitoring as required by the federal Title V permit rules. However, the commission changed the frequency from quarterly to semiannually in response to this comment.

Exterran "supports the proposed engine standards which meet the strict New Source Performance Standards (NSPS) for newly constructed engines in both the proposed Standard Permit and the Permit by Rule. 40 CFR Part 60, Subpart JJJJ."

The commission appreciates the support.

Exterran stated that, "Engine test data confirms low formaldehyde emissions and the Oil and Gas Proposal should not duplicate/conflict with recent federal 40 CFR 61, 63 NESHAP standards and testing requirements (Section C)."

Language in the new OGS rules has been updated to indicate engine testing for formaldehyde is not required unless requested by commission Region. The commission determined that testing for CO can be used as a surrogate for testing for formaldehyde. The determination was based on engine testing for formaldehyde that was submitted for numerous engines; the testing results showed low emissions for and consistency of formaldehyde emissions for groups of engine types.

Exterran requests that the "TCEQ extend the compliance time frame for the smaller hp RB engines to recognize the significant costs but relatively small emission reduction potential from these engines. This extension is also supported by EPA's recent promulgation of NESHAP standards, published on August 20, 2010, which imposes extensive management practices on most SI RICE less than 500 hp to ensure well-maintained engines. (See 40 CFR 63.6603 and Table 2d to Subpart ZZZZ of Part 63 for Existing SI RICE < 500 at area sources of HAPs as finally promulgated in National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule, 75 FedReg 51570 at 51589 and 52595) (August 20, 2010). The new NESHAP ZZZZ regulations impose Management Practices on all existing SI RICE 4SRB < 500 hp at Area Sources for hazardous air pollutants (HAPs) nationwide. The Management Practices require the following actions: Change oil (or confirm oil meets acceptable parameters) and filter every 1,440 hours of operation or annually, whichever comes first; Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and Inspect all hose and belts every 1,440 hours of operation or annually, whichever comes first. The management practices will ensure that 4SRB < 500 hp at Area Sources for HAPs, SI RICE which are most likely authorized by state PBRs and Standard Permits, are operating in a well maintained condition. TCEQ should consider the costs imposed on industry associated with controlling all engines in the state, the relatively small benefit from the smaller engines and the federally imposed management practices for these smaller engines to extend the emission compliance date to 2020 for 4SRB < 500 hp in the Standard Permit and 2030 for 4SRB < 500 hp in the Permit by Rule."

The PBR has been changed to delete standards for rich-burn engines under 500 hp in response to this comment. In addition, after a detailed review of submitted information and federal background documents for 40 CFR 63 NESHAP Subpart ZZZZ, the commission has determined that the requirements of this federal standard is sufficient to establish controls on formaldehyde on new and existing

engines. This is further supported by recent monitoring and does not show any concerns with monitored values of formaldehyde from engines associated with oil and gas production sites. Therefore, formaldehyde is omitted from the impacts evaluation requirements and emission limits for this PBR.

Exterran commented that, "In addition to the extremely low formaldehyde emissions associated with uncontrolled SI RICE, EPA has implemented a series of controls and operational requirements on the hazardous air pollutants (HAPs) emitted from SI RICE. See National Emission Standards for Hazardous Air Pollutants (NESHAP) for SI RICE in Part 63 Subpart ZZZZ. 2) See National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule, 75 FedReg 51570 (August 20, 2010), for the most recent promulgation of NESHAP standards on SI RICE. Taken together, the OEM uncontrolled emission data, additional SI RICE formaldehyde testing, and stringent federal standards focused on formaldehyde emissions from SI RICE strongly support TCEQ's Oil and Gas Proposal that recognizes the low formaldehyde emissions from SI RICE. The final Oil and Gas rule should not impose additional modeling requirements or duplicating existing federal standards and costly testing requirements. Recent SI RICE testing conducted by Exterran for the development of the most recent federal NESHAP ZZZZ amendment for SI RICE also shows the low formaldehyde emissions from SI RICE. In fact, when similar engines make/models from the OEM emission estimate (Attachment C-1) are tested in Attachment C-2, the 2009 formaldehyde test data is lower than the uncontrolled, upper limit OEM emission estimates. 3) Note, the testing protocol in Attachment C-2 was not created to support or confirm the OEM test data in Attachment C-1 but rather to provide additional test data where EPA lacked emission information for specific engine categories in the NESHAP ZZZZ proposal. Over the past 6 years EPA has promulgated three separate rulemakings which impose NESHAP emission standards for all new and existing SI RICE at Major and Area Sources of HAP emissions. 40 CFR Part 63 Subpart ZZZZ (referred to generally as "NESHAP ZZZZ"). 4) In December 2004, EPA issued a rule that controls formaldehyde on engines greater than 500 hp at Major Sources of HAP. In January 2008, EPA issued NESHAP ZZZZ standards for new and reconstructed smaller engines (< 500 hp) at Major Sources of HAP and larger engines (> 500 hp) at Area HAP Sources. Most recently, in August 2010 EPA finalized the HAP emission standards (imposed primarily for formaldehyde emissions) which will impact all existing SI RICE at Area Sources for HAP and all existing SI RICE < 500 hp at Major Sources of HAP. In particular for existing engines, the 2010 NESHAP ZZZZ amendments impose numerical HAP standards on all SI RICE < 500 hp at Major Sources and all SI RICE > 500 hp at Area Sources. (Standards for existing SI RICE > 500 at Major Sources were imposed in the 2004 NESHAP rule.) The NESHAP ZZZZ standards not only reduce HAP emissions from SI RICE, but they also impose extensive and costly compliance testing requirements. The NESHAP numerical standards and testing requirements are outlined below. Exterran requests that TCEQ carefully consider these requirements as an additional argument not to impose additional state formaldehyde emission standards or costly testing requirements on SI RICE with already low formaldehyde emissions. 4) The NESHAP rule defines a Major Source as any source that emits 10 tons per year (tpy) or more of any single HAP or 25 tpy of any combination of HAPs. An Area Source is any source that emits less HAP emissions than a Major source. 4SLB greater than 500 hp at Area Sources must meet the limit of CO 47 parts per million, volume-dry (PPMvd) at 15 percent oxygen or 93 percent reduction in CO for 4SLB > 500 hp. This emission standard requires catalytic controls. (CO was established by EPA as an appropriate surrogate for HAPs from SI RICE, including formaldehyde.) 5) Therefore requiring controls on existing, larger 4SLB engine at Area Sources. This oxidation catalyst requirement significantly reduces any concern from a potential impact from 4SLB engines as the 4SLB engines are also reported to have the highest OEM-estimated formaldehyde emissions and area sources are most likely to be at sites also authorized by a PBR or standard permit. EPA also imposed an emission standard of 2.7 PPMvd formaldehyde at 15 percent oxygen or 76 percent formaldehyde reduction on 4SRB SI RICE greater than 500 hp at HAP Area Sources. To achieve this emission standard for 4SRB SI RICE the owner/operator must also install a catalyst (a non-selective catalytic reduction or NSCR). Because these emission standards are imposed on existing 4SRB engines at Area Sources the existing NESHAP standards will work to implement progressive emission standards on engines authorized at the state level by PBRs and Standard Permits. 5) EPA's 2004 ZZZZ NESHAP proposal included data that supported the use of CO as a surrogate for HAPS, including formaldehyde. See Docket EPA-HQ-OAR-2002-0059-0065 as referenced by EPA's response to comments Response to Public Comments on Proposed National Emission Standards for Hazardous Air Pollutants for Existing Stationary Reciprocating Internal Combustion Engines Located at Area Sources of Hazardous Air Pollutant Emissions or Have a Site Rating Less Than or Equal to 500 Brake HP Located at Major Sources of Hazardous Air Pollutant Emissions, Docket EPA-HQ-2008-0708-0557 at p. 118 (August 10, 2010). 6 Larger sites which are major for HAPs will most likely be authorized by a 116 case-by-case permit. The NESHAP ZZZZ rule also imposes significant performance test and compliance requirements for SI RICE demonstrating compliance with numerical emission standard at Area or Major Sources greater than 500 hp. See the 2010 NESHAP ZZZZ SI RICE Final Rule, Tables 4 – 6, 75 FedReg at 51597 – 51603. Should TCEQ impose additional formaldehyde testing requirements on an estimated 10,000 SI RICE less than 500 hp operating in Texas statewide, that would cost approximately $3,500 annually to test each engine with method 323. Total cost to industry would total over $35,000,000 statewide.

In light of the existing NESHAP federal requirements and the extremely low formaldehyde emissions from SI RICE, additional state-imposed testing for formaldehyde would be unnecessary, costly and show no environmental benefit."

Language in the new OGS rules has been updated to indicate engine testing for formaldehyde is not required unless requested by commission Region. The commission determined that testing for CO can be used as a surrogate for testing for formaldehyde. The determination was based on engine testing for formaldehyde that was submitted for numerous engines; the testing results showed low emissions for and consistency of formaldehyde emissions for groups of engine types.

Exterran commented that, "In the rare instance where the OEM uncontrolled upper limit emission data estimates may exceed TCEQ's lb/hour formaldehyde emission estimate, for example for extremely large lean-burn engines, TCEQ should consider the federal requirements which impose catalytic control requirements on new, reconstructed and existing engines at Area Sources. The emission standards imposed on large 4SLB at Area Sources by the 2010 NESHAP ZZZZ area require an oxidation catalyst to reduced CO levels to 47 PPMvd or achieve a 93 percent reduction in CO emissions. CO emissions are a demonstrated surrogate for formaldehyde emissions and formaldehyde emission reductions. EPA's 2004 ZZZZ NESHAP proposal included data that supported the use of CO as a surrogate for HAPS, including formaldehyde. See Docket EPA-HQ-OAR-2002-0059-0065 as referenced by EPA's response to comments Response to Public Comments on Proposed National Emission Standards for

Hazardous Air Pollutants for Existing Stationary Reciprocating Internal Combustion Engines Located at Area Sources of Hazardous Air Pollutant Emissions or Have a Site Rating Less Than or Equal to 500 Brake HP Located at Major Sources of Hazardous Air Pollutant Emissions, Docket EPA-HQ-2008-0708-0557 at p. 118 (August 10, 2010)."

The commission has changed in the rule in response to this comment. After a detailed review of submitted information and federal background documents for 40 CFR 63 NESHAP Subpart ZZZZ, the commission has determined that the requirements of this federal standard is sufficient to establish controls on formaldehyde on new and existing engines. This is further supported by recent monitoring and does not show any concerns with monitored values of formaldehyde from engines associated with oil and gas production sites. Therefore, formaldehyde is omitted from the impacts evaluation requirements and emission limits for this PBR.

TXOGA stated that, "The Proposal Exceeds Several Federal Requirements, including 40 CFR 60 NSPS KKK, 40 CFR 60 NSPS JJJJ testing."

The federal requirements listed in 40 CFR Part 60, Subparts JJJJ and KKKK apply to only very new facilities. The commission is obligated to examine all faculties when proposing a PBR. The commission attempted to allow any federal requirements to be acceptable for the proposed PBR.

One individual state that "Since 1991 I have estimated emissions and permitted many sites with glycol dehydration systems. In Texas I have permitted many facilities with these systems utilizing the same emission estimation method since 1996. TCEQ has recently stated that the results of GRI-Gly Calc Model version 3.0 or higher may not be used to determine condenser performance. The EPA has not only documented acceptance of this method in 40 CFR Part 63 Subpart HH Section 63.772 but has also released several studies and letters advocating the use of GRI-Gly Calc. Several other states in which I am currently working and have worked for during the past 20 years follow EPA guidelines and accept GRI-Gly Calc. Instead of accepting this methodology, the TCEQ has recently stated that it will only accept a reductive efficiency of 80 percent for glycol dehydration systems equipped with only a condenser on the glycol still column. Recently TCEQ provided a letter dated March 4, 1994 and I was told that this was the basis for the 80 percent policy. Upon review of the letter I discovered that this letter was probably based in part on my air emissions work and research from 1991 through 1993. If so, my data was neither intended for nor relevant to the creation of such a policy. The TCEQ further stated that an additional 6 percent reduction in overall emissions from the glycol dehydration system may be taken if the system is equipped with a glycol flash tank. This brings the overall allowed reduction in emissions to 86 percent for a glycol dehydration system equipped with a glycol flash tank and still column condenser. The problem with such a policy is not only that the 86 percent is incorrect but also because of the regulatory ramification that results. Without a proper understanding of the glycol dehydration systems operations and emission estimations by the TCEQ, the crude oil and natural gas industry in Texas will be in a "Catch 22" situation and required to install expensive, needless control equipment. In order to claim a PBR a site must conform to Texas Administrative Code (TAC) Title 30 Section 106.4 by demonstrating Volatile Organic Compound (VOC) emissions below 25 tpy. Once a site is authorized under a PBR, the site has limited compliance requirements. A site that claims a PBR is not required to install emission controls on a glycol dehydration system. However, most sites without some form of emission control device on the glycol dehydration system would result in the site exceeding the PBR limits of 25 tpy of VOCs. In addition, most sites with a glycol dehydration system only allowed by the TCEQ must apply a total reductive efficiency of only 86 percent for the glycol flash tank and still column condenser resulting in site wide VOCs exceeding the 25 tpy limit. Therefore, this will force a site to obtain a Standard Permit in accordance with TAC Title 30 Part 1 Chapter 116. Once a site is authorized under a Standard Permit, a glycol dehydration system with uncontrolled emissions of 10 tpy VOCs must be controlled in accordance with TAC Title 30 Part 1 Chapter 116 Rule 116.620.a.5. Per TAC Title 30 Part 1 Chapter 116 Rule 116.620.b.2 a glycol dehydration system with uncontrolled VOC emissions of 10 tpy must be controlled by at least 80 percent and a system with 50 tpy or more must be controlled by at least 98 percent or 95 percent depending on the control device used. Most systems uncontrolled and without a glycol flash separator will exceed 50 tpy VOCs. TCEQ's policy to only allow 86 percent reduction for glycol flash tank and still column condenser will result in a "Catch 22" that forces almost all dehydration systems to install an expensive control device accepted by the TCEQ to be at least 95 percent efficient. This will affect many thousands of glycol dehydration systems in the State of Texas for the crude oil and natural gas industry. The potential unwarranted costs to the crude oil and natural gas industry in Texas would be staggering. To avoid this needless expense and other ongoing regulatory requirements that will consume field personnel's time, the TCEQ need only to understand the operation and emission estimations of a glycol dehydration system. It has been and is my sincere intent to help the TCEQ understand the intricacies of a glycol dehydration system. One of the key aspects of a glycol dehydration system in relation to operations, emissions and regulatory concerns is the glycol flash tank. A glycol flash tank whose gases are not released but rather routed back into the sales gas line system is not a control device but a component of the process equipment. The TCEQ has deemed glycol flash tanks as a control device and only allow an additional 6 percent reduction in emissions from the glycol dehydration system even if 100 percent of the gases from the glycol flash are routed back into the sales gas line system. Of all the aspects of operation and emission estimation that eluded the TCEQ, the flash tank is the most important. The flash tank back pressure valve is adjustable. Lowering the flash tank pressure allows more of the gases entrained in the rich glycol to escape which may then be routed back into the sites sales gas line system. This substantially reduces the amount of gases eventually released in the still column resulting in a greater achieved efficiency for the still column condenser. Another possible added benefit of lowering the glycol flash tank pressure is the recovery and sale of additional gas. If the TCEQ wants to really do some good they should require glycol flash tank pressure be set at no more than 20 percent of the sales gas line system in which the gases are routed (if operationally feasible). In fact a simple adjustment with a wrench can be made in less than a minute to the glycol flash tank that would increase the overall efficiency of a glycol dehydration system from 10 to 97 percent. With such a large variation in efficiencies due to a quick adjustment to only one part of the glycol dehydration system, it seems implausible that the TCEQ would set the efficiency at 86 percent for all glycol dehydration systems equipped with a glycol flash tank and condenser no matter how these devices are designed or operated. The glycol flash tank pressure is only one part of the glycol dehydration system that tremendously affects the system's overall emissions. There are many other aspects that affect a glycol dehydration system's emissions. Some of these aspects remain relatively constant such as: natural gas flow rate, gas pressure, gas temperature, and inlet dew point. A few other conditions that can easily be adjusted in the field within minutes that greatly affect emissions include, but are not limited to: glycol pump strokes per minute, flash tank temperature, dry gas dew point, and reboiler temperature. Therefore, to accurately estimate emissions from a glycol dehydration system it is necessary to completely understand the system and all possible variables. In the last few years and especially in the past few weeks I have attempted to relay this information to the TCEQ so that we may discuss a more appropriate estimation of emission as well as conformity to both State and Federal requirements. From recent communication with several TCEQ representatives it is was amply demonstrated that there was a lack of sufficient understanding of the system, emission estimations, and applicable Federal regulations (40 CFR Part 63 Subpart HH). I respectfully request a meeting with the TCEQ so that we may work together and utilize all resources to achieve our common goal. I have been informed that certain TCEQ employees have been directed not to speak with me. I feel that this is unwarranted and not beneficial to the crude oil and natural gas industry, my current and future clients, my company, and the TCEQ air program. As a consultant in the crude oil and natural gas industry for the past 20 years, I feel that my knowledge and insight should be utilized to help the TCEQ develop an economically and operationally feasible method of compliance with all State and Federal air regulations."

The commission has revised the rule to allow the use of GRI-Gly Calc and specifically support the proper use of this program with good site specific data.

EPA expressed concerns that "there is significant variability in the in-stack ratios of NO to NO_2 and recent data that EPA has collected on engines that burn natural gas has indicated that the in-stack percentage of NO_2 has been monitored at 40 - 60 percent for some engines. We believe that the PBR and standard permit should require site specific monitoring (potentially using a portable analyzer) to verify the in-stack NO to NO_2 ratio and if it is higher than the percentage used to support the PBR or standard permit, that the source be remodeled and obtain a regular construction permit We also believe the analysis for one-hour and annual NO_2 standards should be updated to a more conservative in-stack ratio."

Exterran commented that, "Recently conducted emission tests on SI RICE demonstrate that a 75 percent estimate of NO_2 to total NO_X grossly overestimates NO_2 from these engines. In 2009, Exterran conducted approximately 85 reference method emission tests and also reviewed recent portable emission tests of SI RICE engines. These tests demonstrate that although NO_2 levels of total NO_X differ based upon the engine type, e.g., 4SRB, 4-stroke lean-burn (4SLB), or 2-stroke lean-burn (2SLB) RICE, all conversion rates were dramatically less than 75 percent. Attachment B-1 details Exterran's data collection for NO_2. The total NO_X to NO_2 percentage varies by engine type and is averaged as follows: 4SRB 0.86 percent; 4SLB 9.66 percent; 2SLB 41.48 percent."

The optional method of assuming all VOCs consistent with the most restrictive ESL under worst-case dispersion and closest distance to a receptor has been deleted based on comments stating that this option is too restrictive to be a meaningful tool for a project or registration. NO_2 to NO_X ratios have been updated based on engine testing as provided by companies, vendors, or manufacturers. The typical $NO_2$to NO_X ratio from engine sampling commonly seen by the commission ranges from less than 5 to 40 percent. The annual NO_2 NAAQS has an EPA-approved modeling default ratio of 0.75. The current one-hour NO_2 NAAQS has an interim modeling default ratio of 0.75 as well. That means that 75 percent of the NO_X emitted is assumed to be NO_2 and modeled as such. The commission believes

using the 0.75 ratio is too conservative for the one-hour standard given several important factors. First, actual sampling data received in response to comments shows that the percentage of NO_X that is NO_2 immediately prior to release into the atmosphere ranges from 2 to 20 percent with the majority less than 15 percent for 4-stroke rich-burn and 4-stroke lean-burn engines. This is well below the modeling default ratio of 0.75. Secondly, NO is oxidized to NO_2 in the atmosphere by reaction with other molecules (ozone, etc.). This requires time, but the plume also is being dispersed the farther from the stack it travels. So, while the ratio of NO_2 to total NO_X for a given section of the plume may be slowly increasing to an equilibrium ratio of 0.75, the total NO_X concentration is dropping as distance from the stack increases. The maximum ground level impact of NO_2occurs where the product of the NO_2/NO_X ratio times the total NO_X concentration is the greatest at any given location. Given how quickly ground level concentrations usually drop as distance increases and the time needed to reach equilibrium, this maximum NO_2 impact tends to be relatively close to the emission point. A previous compressor station study by the commission showed that the NO_2/NO_X ratio appeared to max out at around 14 percent in the area downwind of the studied site where maximum NO_X concentrations were expected. Upon review of this information, the commission has determined it is reasonable to allow a lower NO_2/ NO_X ratio. Given the submitted sampling data and previous commission experience, a ratio of 20 percent is appropriate for 4-stroke engines. Several 2-stroke lean-burn engines in the submitted data set emitted about 50 percent NO_2 and the commission believes the ratio of 50 percent is appropriate for 2-stroke engines. The commission does not anticipate allowing lower values than these due to the

complexity of validating site specific values. Sites wishing to use a lower ratio may have to perform ambient air monitoring for NO_2 at the predicted location of the maximum ground level impact of NO_2.

Exterran suggested "NO_X to NO_2 conversion emission data for SI RICE merit higher site wide NO_X thresholds for impact analysis."

The commission agrees with this comment. With all other things being the same, allowing a 0.5 or 0.2 ratio will result in higher NO_X values from engines being able to demonstrate compliance with NAAQS.

Hourly/annual limits

ETC recommends rule changes: "The total of all emissions from the facilities at an OGS requiring single authorization pursuant to subsection (b)(5)(A) shall not exceed 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."

The commission believes that the wording suggested conveys the same meaning as the one proposed by the commission. The only change made to this part is that subsection (b)(5)(d) was moved to subsection (b)(6)(g) for better organization and particulate matter was separated into $PM_{2.5}$ and PM_{10}, with 15 and 10 tpy limits, respectively. Based on commission permitting staff experience, it is highly

unlikely the particulate matter limits will ever be exceeded for an OGS authorized with this authorization type.

EDF commented that the "The total allowed increases for NO_X and VOC are too high. Basing these values at the federal NSR applicability trigger (even at the most stringent such threshold) is not adequate for OGS sources whose emissions are supposed to be insignificant. Instead, the TCEQ should limit the total increases to the annual values proposed in §106.352 (c)(1)(B), and those values should be reduced accordingly. If the TCEQ does not reduce the allowed amount of emissions increases, then it should provide a quantitative demonstration that such emissions increases would not materially affect the results of a prior protectiveness review."

The commission appreciates the concerns raised with regard to additions and changes to facilities which do not require registration; however, the commission has not changed the values for NO_X and VOCs total allowed emissions that do not require registration for existing OGS which are authorized by previous versions of this section. The commission has established *de minimis* increases below which no protectiveness review is needed and codified these values in subsection (k)(3)(C) and compared these values against those in subsection (c)(1)(B)(iii). In subsection (c)(1)(B)(iii), the commission establishes that in order for registration to not required at an existing site authorized under previous versions of the oil and gas PBR, total increases over a rolling 60-month period of time must be less than or equal to 5.0 tpy VOC or NO_X, 0.05 tpy benzene, or 0.1 tpy H_2S. 5.0 tpy VOC, on a steady state emissions basis, is equivalent to 1.14 lb/hr. At the lowest modeled emission release height of 3 feet and shortest distance to receptor of 50 feet, the

amount of VOC determined to be protective based on the fugitive generic modeling results and the crude oil/condensate short-term ESL of 3,500 µg/m^3 is 0.8 lb/hr. The 0.23 lb/hr is less than 30 percent of 0.8 lb/hr. The 0.05 tpy benzene, which on a steady state emissions basis, is equivalent to 0.01 lb/hr benzene, is about 25 percent of the *de minimis* value set for benzene, about 0.04 lb/hr. The 5.0 tpy NO_X, which on a steady state emissions basis, is equivalent.

The commission establishes a 1.0 tpy VOC limit, which is equivalent to 0.23 lb/hr total VOC. This value is less than 30 percent of the amount which would be at the ESL for crude oil or condensate at a 3-foot fugitive release at the minimum distance of 50 feet from a receptor. Based on the limit of 0.01 tpy benzene, the maximum amount of emissions would be 0.0023 lb/hr. This amount is 6 percent of the ESL at the most conservative dispersion (3-foot fugitive release at 50 feet). For NO_X at 5 tpy, this would be equivalent to 1.14 lb/hr released, which is much less than the 4.0 lb/hr *de minimis* exemption in subsection (k). For H_2S, the equivalent hourly release of 0.05 tpy is 0.0114 lb/hr, or about 46 percent of the most restrictive property-line standard. Due to the very conservative nature of this analysis, the commission has no concerns regarding protection of public health and welfare.

EDF stated that the rule should be revised to read: "Planned downtime of any capture, recovery, or control device must be considered when evaluating emission limitations of this section, and {if needed} to the maximum extent practicable, gas streams shall be redirected to another control or recovery device during downtime."

The commission has changed this concept in the rule. This requirement is no longer included in the best management practices subsection (e) and the requirements have been moved to subsections (g) and (h) as it includes considerations for emission estimation and is not clearly a simple BMP. Nowhere in the rule is a control required unless it is needed to meet the applicable emission limits.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented that, "According to its own words, TCEQ has "dedicated a huge amount of time and resources to the question of Barnett Shale air quality as a result of oil and gas operations in the area." TCEQ's effort has included a significant amount of multi-day mobile monitoring projects and stationary site air monitoring that have been, and are, focused on determining if emissions from OGS in the Barnett Shale area are causing negative short-term or long-term health impacts. The data from such monitoring, and toxicological evaluation of such data, do not support TCEQ adoption of a PBR or standard permit that is more stringent than the current PBR or standard permit, much less the much more stringent Proposed PBR and Proposed Standard Permit. The TCEQ Toxicology Division of the TCEQ Chief Engineer's Office has consistently determined, based on the TCEQ's mobile and stationary monitoring activities, that the emissions from OGS in the Barnett Shale area are not causing any negative short-term health impacts. The TCEQ Toxicology Division made these determinations based on comparisons of the monitoring data to TCEQ's short-term health-protective and welfare-protective air monitoring comparison values ("AMCVs") for the relevant chemicals. AMCVs are "set to provide a margin of safety and are set well below levels at which adverse health effects are reported in the scientific literature," such that a monitored concentration of a chemical above its AMCV "does not necessarily mean that adverse effects will occur, but rather that further evaluation is warranted." As a result, the TCEQ's determination that there have been no negative short-term health impacts from OGS emissions in the Barnett Shale area based on comparison of monitored concentrations to chemicals' AMCVs is a very conservative and overly protective determination."

TPA commented that a third area of the proposed PBR that imposes requirements stricter than those imposed by federal law are the provisions that establish a lb/hr limit as a criterion for threshold applicability in order to qualify for Levels 1 (subpart (g)(2) and (g)(3)) and Level 2. Under the NSR, PSD and Title V permit programs a tpy threshold is established. While lb/hr limits may be set in a federal NSR or PSD permit, the criteria to determine whether applicability is triggered are based off of a potential to emit expressed in terms of tpy. Under the proposed PBR, a lb/hr limit would determine whether a facility qualified for any particular level of the PBR. This is overly prescriptive and not justified given the insignificance of these sources, by definition.

The commission is keeping lb/hr limits, although some have changed from the proposed values based on revised modeling. The commission believes that it has set appropriate limits which are stringent enough to ensure protectiveness, but not overly conservative so as to be unrealistic to be met. The TCAA clearly states the intent of permitting and regulatory actions by the agency is to "vigorously

enforce" regulations to "safeguard the state's air resources from pollution" (see THSC, §382.002). To appropriately regulate air emissions and issue authorizations for facilities (see THSC, §382.003 and §382.0518),, the legislature also passed laws giving the TCEQ the ability to generate standardized and streamlined mechanisms. While these mechanisms are developed and implemented, they must continue to protect the public health and welfare. As a part of these mechanisms, the protectiveness criteria established in PBRs and standard permits typically includes emission limits with rates paralleling the ESL guidelines and ambient air standards in lb/hr and tpy. THSC, §382.0518 and §382.085 specifically mandate the commission to conduct air permit reviews of all new and modified facilities to ensure that the operation of a proposed facility will not cause or contribute to a condition of air pollution. In the review of proposed emissions, federal/state standards and contaminant-specific ESLs are used, respectively, for criteria and non-criteria pollutants. Because of the comprehensiveness of the language in the THSC, ESLs are developed for as many air contaminants as possible, even for contaminants with limited toxicity data.

Each oil and gas production site may individually contribute air contaminants to the ambient air which may not be detected by monitors given the practical limitation of having monitors covering the entire state. Data from the current monitoring network does not reflect a site-by-site picture of ambient air quality due to the limited number of monitors. Permitting and regulatory requirements for reporting and monitoring are put in place to supplement the data from TCEQ's monitors and allows the TCEQ to obtain a comprehensive data set. The TCEQ uses

this data to ensure that the state's air resources are safe-guarded and that the public's health and welfare is protected. The proposed PBR and standard permit revisions include a site-specific evaluation for new registrations to ensure that these operations meet the intent of the Texas Clean Air Act while striving to avoid overly burdensome requirements.

Further, over the last 5 to 10 years, scientific research has progressed so that more accurate quantification of potential and actual emissions from oil and natural gas production is now available. This information has prompted further review of the nature of emissions that may be released from these sites. The new research provides helpful information regarding possible exposure concerns for the general public, particularly when in close proximity. Consequently, the proposed revisions to the oil and gas PBR and standard permit are evolving through a detailed analysis and evaluation to ensure TCEQ requirements reflect good science.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented that, "The benzene levels detected at the monitors are lower than in metropolitan areas around the country. In summary, the air monitoring and toxicological studies TCEQ has conducted have not shown that the emissions from OGS in the Barnett Shale area are causing any negative short-term or long-term impacts. Moreover, none of the reputable air monitoring studies that other entities have conducted relative to emissions from OGS in the Barnett Shale area have shown otherwise. In addition to the air monitoring and toxicological studies TCEQ has conducted, the Texas Department of

State Health Services ("TDSHS") collected and analyzed blood and urine samples from people living in or near DISH, Texas to evaluate possible exposure to VOCs from gas wells and compressor stations in the vicinity. Based on the TDSHS' analysis, TDSHS concluded that there was no indication of elevated, community-wide exposure to VOCs emitted from OGS. In conclusion, the data from the reputable air monitoring and toxicological studies and TDSHS' health study do not provide support: (i) for the conclusion that current PBR §106.352 or the current standard permit in 30 Texas Administrative Code §116.620 are inadequate to protect the health and welfare of the people in the vicinity of OGS in the Barnett Shale area, or any other areas where OGS are located, or (ii) for adoption of the much more stringent Proposed PBR or Proposed Standard Permit. When reviewing agency rulemakings, there is no presumption that facts exist to support the agency's order. As discussed in more detail in these comments, TXOGA contends that not only has TCEQ not provided facts to support the Proposed Rules, the great weight of scientific analysis - much of it conducted by TCEQ - leads to the conclusion the facts do not support adoption of the Proposed Rules as presently written. Further, the TCEQ has not made any finding that the data from the mobile or stationary air monitoring activities support a determination that any negative long-term health impacts are resulting or have resulted from the emissions from OGS in the Barnett Shale area. TCEQ has determined that it is inappropriate to use short-term monitoring concentrations for a chemical to determine whether the emissions of that chemical will cause any negative long-term impact. According to TCEQ, "simply taking an instantaneous air sample and then trying to draw conclusions about a long-term health concern is a difficult and complex scientific task, and made all the more difficult when dealing with measured amounts of chemicals that are very low." TCEQ has properly stated that the appropriate way to determine whether emissions from OGS in the Barnett Shale area may cause a negative long-term impact is to conduct long-term monitoring at stationary sites in the area. TCEQ has been conducting long-term monitoring at stationary Volatile Organic Compound ("VOC") monitors near oil and gas activity and the Dallas/Fort Worth Metroplex for VOCs, including benzene, since 2000. The annual average VOC concentrations from such monitoring have all been less than the long-term health comparison values."

Devon commented that, "Imposing hourly limits of VOC is unjustified and should not be required for demonstrating protectiveness, as these limits were determined in an arbitrary manner. This requirement is redundant to demonstrating protectiveness for benzene, and VOC emissions are subject to annual requirements."

The commission is keeping lb/hr limits, although some have changed from the proposed values based on revised modeling. The commission believes that it has set appropriate limits which are stringent enough to ensure protectiveness, but not overly conservative so as to be unrealistic to be met. Short-term ESLs are based on data concerning acute health effects, odor potential, and acute vegetation effects, while long-term ESLs are based on data concerning chronic health or vegetation effects. Therefore, before a short-term or long-term ESL can be selected, available information on each of these health and welfare effects is obtained as described in the following sections. The staff has evaluated the need for standardized maximum pollutant caps with individual registration impacts evaluation with property lines or receptors within 1/2 mile following the mechanisms used for case-by-case state permit authorizations. It is always expected that monitored values are less than predicted concentrations with worst-

case permitting tools.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented that, "The annual average benzene concentrations, determined at two stationary monitors "located near oil and gas activity" since 2000 and 2003, respectively, have ranged from 0.144 ppbv to 0.35 ppbv, which is much less than the long-term health-based comparison value for benzene of 1.4 ppbv. Further, the attached Exhibit 1, which is a TCEQ graph and a TCEQ chart available on TCEQ's website, is described by TCEQ as an illustration that "the annual benzene averages from Auto-GC air monitors in the Dallas-Fort Worth-Barnett Shale area are substantially lower than the long-term {AMCV} of 1.4 ppbv." Exhibit 1 is incorporated herein by reference. Thus, the annual average concentrations of VOCs, including benzene, from the TCEQ's long-term monitoring demonstrate that the emission of VOCs, including benzene, from OGS in the Barnett Shale area are not causing any negative long-term impact. Notwithstanding the conclusions reached by TCEQ, based on air quality monitoring and toxicological studies of the Barnett Shale area, the TCEQ Toxicology Division recommended that TCEQ conduct "additional stationary long-term monitoring in the (Barnett Shale) area to better assess the influence of oil and gas activity on ambient concentrations of VOCs, particularly benzene, on a regular basis over a long period of time." In response to that recommendation, in the spring of 2010, TCEQ installed two new stationary monitors in the Barnett Shale area and began to collect long-term VOC data at those monitors. To TXOGA's knowledge, none of these data indicate that the emissions from OGS in the Barnett Shale area are causing any negative long-term impacts (or short-term impacts)."

The commission has reassessed the particular values for the hourly caps of each

PBR level to ensure reasonable justification and ability of a majority of sites to meet the limits based on currently reviewed registrations (with limited exceptions).

TIPRO commented that, "If TCEQ determines that the current schedule for adoption of these rules is to be strictly adhered to despite objections; TIPRO recommends that the agency modify the proposed rule package for permit by rule to exempt wells that operate at a *de minimis* production level. This would allow operation of marginal wells to remain a viable and worthwhile venture, while still allowing the TCEQ to account for larger potential sources of emissions."

The commission has changed the rule in response to this comment. Based on additional information submitted, field visits by agency staff, and further research on smaller combinations of facilities, the commission has added subsection (c)(4) to further streamline authorizations and appropriately focus agency and industry resources.

TAEP commented that, "Level 1 Registration places a burden on both the regulated community. This could be mitigated and greatly reduced by establishing: *de minimis* standard based on emission level thresholds; *de minimis* standard based on site configuration; *de minimis* standard based on oil/gas/condensate production volume; a one-time registration using best available data."

The commission has changed the rule in response to this comment. Based on additional information submitted, field visits by agency staff, and further research on smaller combinations of facilities, the commission has added subsection (c)(4) to further streamline authorizations and appropriately focus agency and industry resources. In addition, the commission has changed various restrictions on Level 1 in response to this and similar comments. The commission has changed the registration requirements, eliminated source type restrictions, allowed representative gas and liquid analyses, eliminated redundant records, and made other changes to make this Level more meaningful and flexible for industry while maintaining protective limits, ensuring a complete public record, and ensuring practically enforceable requirements.

Targa commented that, "Targa submitted 24 PBR applications in 2009. Several of these projects could not have complied with the hourly VOC limit in the proposed standard during condensate loading operations or scheduled maintenance on VRUs which would have in turn required submittal of a minor NSR permit application. It is important to recognize that while these hourly emissions may exceed the proposed PBR limits, the annual emissions are low and the overall emissions from the site are minor. Targa believes that the TCEQ should remove the hourly emission limits from the PBR and just require demonstration of meeting the modeling standards to ensure protectiveness. Further, Targa supports the comments provided by the Texas Oil and Gas Association (TXOGA) and the Gas Processors Association (GPA) regarding modeling standards."

ETC commented that, "Short-term VOC limits for Level 1 and 2 are unrealistically low. The PBR Level I and 2 authorizations restrict total VOC emissions based on an arbitrary lb/hr basis and do not relate to any state health effects levels. If the TCEQ is trying to provide protectiveness for specific pollutants, e.g. benzene and toluene, then protectiveness can be reviewed on an individual pollutant basis without imposing restrictive VOC limits on locations that emit insignificant quantities of these pollutants. The VOC limits proposed in these rules are based on a specific benzene concentration relationship that is extremely conservative and overly restrictive. Consequently, a site with little or no benzene in its natural gas would be required to have an overly restrictive and arbitrary total VOC limitation to limit benzene emissions, which in reality do not exist."

TPA commented that, "The proposed hourly limits for VOCs are set too conservatively. It is apparent that the VOC lbs/hr limits were very conservatively set, based on the ESL of 3,500 for crude oil and condensate. Engines that are covered by the PBR will not be burning crude oil or condensate; rather, VOCs from engines will result from un-combusted natural gas. The ESL for un-combusted natural gas is 18,000, not 3,500. Therefore, it is apparent that the VOC lbs/hr limits currently proposed in the PBR are far too conservative. TPA suggests that the VOC lbs/hr limits in the PBR be revised so as to account for the higher ESLs applicable to un-combusted natural gas. TPA further stated that the hourly limits provisions in the PBR should be altered to account for rare events and increased distance to receptors. As noted elsewhere in these comments, including hourly limits provisions in the PBR would be extremely onerous. Under such provisions, a single isolated incident could force an operator into an entirely new regulatory category, even if the incident was not repeated for the remainder of the year and even if the incident took place far from any receptors, rendering the event both isolated and irrelevant in terms of impact. TPA urges TCEQ either to eliminate the hourly limits provisions altogether, or at the very least to amend those provisions to account for the situation where the event (e.g. blowdown or loading) is extremely rare and also to account for the situation where the incident in question took place a substantial distance away from a receptor. Any hourly limits in the PBR should be modified to make them less onerous if greater distances to receptors are involved."

Encana commented that, "Based on the analysis review described by the TCEQ in the proposed PER and Standard Permit preambles, the short-term ESLs for crude oil and condensate (3,500 ug/m3) were used for the determination of the proposed VOC hourly limits. These levels are overly conservative if applicable to combustion sources considering that the character of the "un-combusted" VOC in the natural gas is different than the character of the VOC emissions evaluated by the commission on its analysis (condensate and crude all truck loading emissions). Encana recommends that the TCEQ Includes two VOC hourly limits in this authorization mechanism: one based on a more appropriate ESL for natural gas (18,000 ug/m3) versus the ESL for the crude oil and condensate (3,500 ug/m3) which are not typically burned in engines or other combustion devices."

ETC and TPA commented that, "The 10 tpy VOC limit for Level 1, Tier 2 emissions is unrealistically low. There is no basis for the 10 tpy VOC limit in Level 1, Tier 2 (subsection (g)(3)(A)). In the context of VOC emissions at typical OGS, 10 tpy is a low threshold that will be easily exceeded by many small or medium-sized facilities. Consequently, the inclusion of a 10 tpy threshold for Level 1, Tier 2 will place many small and medium-sized facilities into the Level 2 PBR, which includes preconstruction registration and approval requirements. Inasmuch as such preconstruction registration and approval requirements will subject operators to case-by-case review by agency staff, only the largest, most complex sites should trigger the Level 2 requirements. Accordingly, the 10 tpy figure for VOCs in subsection (g)(3)(A) should be increased. ETC suggests that the VOC limit be increased to at least 20 tpy."

PBPA commented that, "The proposed new annual VOC emissions limit of 10 tons/yr (Chapter 106 . . . down from 25 tons/yr) will greatly increase the number of facilities required to comply with the standard permitting process. These companies are presently covered by the existing TCEQ Permit by Rule."

TPA commented that, "The proposed hourly limits for VOCs are set too conservatively. It is apparent that the VOC lbs/hr limits were very conservatively set, based on the ESL of 3,500 for crude oil and condensate. Engines that are covered by the PBR will not be burning crude oil or condensate; rather, VOCs from engines will result from un-combusted natural gas. The ESL for uncombusted natural gas is 18,000, not 3,500. Therefore, it is apparent that the VOC lbs/hr limits currently proposed in the PBR are far too conservative. TPA suggests that the VOC lbs/hr limits in the PBR be revised so as to account for the higher ESLs applicable to un-combusted natural gas. In addition, the hourly limits provisions in the PBR should be altered to account for rare events and increased distance to receptors. As noted elsewhere in these comments, including hourly limits provisions in the PBR would be extremely onerous. Under such provisions, a single isolated incident could force an operator into an entirely new regulatory category, even if the incident was not repeated for the remainder of the year and even if the incident took place far from any receptors, rendering the event both isolated and irrelevant in terms of impact. TPA urges TCEQ either to eliminate the hourly limits provisions altogether, or at the very least to amend those provisions to account for the situation where the event (e.g. blowdown or loading) is extremely rare and also to account for the situation where the incident in question took place a substantial distance away from a receptor. Any hourly limits in the PBR should be modified to make them less onerous if greater distances to receptors are involved."

The commission has changed the hourly emission values in Level 1 and 2 of the PBR to more realistically establish limits. Based on comments the commission has revised the hourly limits for crude oil and condensate, both for steady-state releases, and periodic emissions. The commission has also added a limit for natural gas, and reviewed and revised all other pollutant hourly limits to more flexible values. All of these limits are a result of evaluations against ESLs. Based on hundreds of currently registered PBRs, more than 95 percent of all emissions registered and certified will comply with the limits in subsections (g) and (h) of the PBR.

EDF commented in "support of the inclusion of specific hourly and annual VOC limits, along with such limits on other specific pollutants identified in the proposal. In no case should the TCEQ increase any of the proposed Level 1 emission thresholds in the final rule. In some cases, the TCEQ should lower the allowable emissions: specifically at least in the case of sour gas facilities. The proposed emissions limits of 0.5 – 2 lb/hr (2.2 – 4.5 tpy H_2S) appear to represent a weakening of existing PBR limits for sour gas facilities. The current PBR rule does not allow emissions greater than 0.27 lb/hr unless the vent height is greater than a minimum of 20 feet, depending on the emissions rate. No such restriction is included in the proposed revision to the PBR. Second, the existing rule does not allow sour gas facilities to be located less than 1/4 mile from receptors, but the proposed revision would allow sour gas sources to be located as close as 50 feet from a receptor. Given the disaster potential and acute hazard posed by H_2S (such as in the case of a large leak or a pipe break), the TCEQ should not weaken the existing PBR requirements for sour gas facilities. The TCEQ should require sour gas facilities to meet a minimum setback distance of 1/4 mile and emissions limits for H_2S that are no less stringent than those required by the current PBR."

The commission did not change the hourly emission limits in response to this comment. As a result of various comments from this and other commenters on the protectiveness evaluation and modeling evaluation, the commission reassessed the way that sources were evaluated, and used realistic, but generally conservative, values to establish emission limits for Levels 1 and 2 of the PBR. While these values in some cases may be different than the previous version of the rule, the new limits are based on an updated analysis using current tools and science. Particularly for H_2S, the commission has determined that an automatic 1/4 mile distance limitation is not needed. It should also be noted that the actual limit for a site is the more stringent of either the level limits or the limit as determined by the protectiveness review, which takes into account both the distance to the nearest receptor (or property line for ambient air standards evaluations) and the emission release height.

TPA commented that, "It would be much simpler if the PBR had but a single level, applicable to all sources, without the attendant lb/hr measurements and the pre-approval requirements currently in the proposal. If TCEQ retains the multi-level structure in the final PBR, then TPA suggests that certain revisions be made with respect to the content and applicability of those levels."

The commission partially agrees with this comment and reduced the number of levels in the PBR from three to two and simplified the differences between the remaining levels.

Devon commented that, "Imposing hourly limits for all OGS, including those sites with less than 5 tpy VOC, represents unwarranted and unreasonable regulatory oversight for insignificant sources, as hourly calculations and/or emissions modeling will be required for all sites to demonstrate protectiveness. Rather than requiring hourly limits for each level of the PBR and requiring demonstration of hourly limits via the modeling tables (Tables 2-6 in the PBR), Devon recommends that protectiveness be demonstrated through the use of the modeling tables and rely on the annual emission limits to set the appropriate permitting level. Sites with less than 5 tpy VOC with sweet production should be exempt from modeling calculations."

The commission has changed the rule in response to this and similar comments. Based on additional information submitted, field visits by agency staff, and further research on smaller combinations of facilities, the commission has added subsection (c)(4) to further streamline authorizations and appropriately focus

agency and industry resources. The commission respectfully disagrees with the commenter that the restrictions and requirements of Level 1 of the PBR, which is for small sites, is unwarranted and unreasonable. To ensure that any oil and gas facility or group of facilities is accurately accounting for emissions, keeping equipment in good working order, and being protective, the commission supports the PBR requirements.

ETC commented that the "TCEQ has proposed requirements for the Texas oil and gas industry that are not equitable with other Texas industries. Examples of provisions in the proposed PBR that would unfairly single out the oil and gas industry for discriminatory treatment include the provision of emission requirements that are limited on a lbs/hr basis, which are not included in PBRs for other industries."

The commission respectfully disagrees with this comment. The oil and gas industry is not being discriminated against compared to other industry segments by the PBR including hourly emission limits. Currently, 29 of the approximately 100 PBRs have hourly or short-term limits on emissions for mechanical, construction, agricultural, chemical, combustion, manufacturing, coatings, waste processes and remediation facilities. In addition, 11 of the 20 standard permits includes specific hourly limits, covering agriculture, lumber, power generation, fertilizer, boilers, and various other industries or facilities.

The Sierra Club commented that they were "concerned about whether the modeling and assumptions used for setting limits in the proposed authorizations accurately reflect potential emissions and provide adequate public health protection. We have identified some assumptions used in the modeling that cause concern. First, we are concerned that TCEQ's proposed VOC limits are not sufficiently protective of public health. In setting the VOC limits, TCEQ assumed a 3 percent average weight of benzene. TCEQ states that this value was selected based on an "average" from viewed facilities. However, it is troublesome that 3 percent was used as an assumption when reviewed facilities demonstrated significantly higher benzene percentages up to 18 percent. Then, TCEQ relied on this selected benzene average when setting a VOC limit in subsection (g)(2). TCEQ again selected an "average" from the reviewed data points for VOCs, selecting 27.01 lb/hr when the data set included a range up to five times higher at 119 lb/hr. We find it problematic that the proposed permit limits are based on these assumptions. Presumably TCEQ used an arithmetic mean when it refers to "averages." To provide a more accurate understanding of the data, it would be helpful if TCEQ would provide the mean, median, and mode of its datasets and a discussion of why the mean was the appropriate representative for setting emission limits."

The commission appreciates the concerns raised by the commenter. With regard to the 3 percent statement in the proposal preamble, the commission has re-evaluated the emission limitations for benzene and finds that this value is not relied upon to establish appropriate benzene emission limits. Instead, the hourly and annual limits for benzene are based on conservative dispersion parameters and the benzene ESLs in proposed subsections (g) and (h).

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Hourly limits for Level 2 should be based on: Flare limit based on 40ft stack at a distance of 2700 feet; Purging limit based on 10ft stack at a distance of 2700 feet; Engine limit based on 20ft stack (>1000hp) at a distance of 2700 feet. Typical emissions are more accurately represented as natural gas rather than liquid condensate or oil. We propose to add the option of meeting a total natural gas hourly limit or a VOC hourly limit in addition to the annual VOC limit. Process vents and blowdowns limits based on 30-foot process vent at a distance of 2700 feet; Tanks and truck loading limits based on a 20-foot tank at a distance of 2700 feet; VOC emissions based on a calculated Condensate Vapor Space ESL based on the TCEQ liquid speciation used in their Interim condensate ESL determination."

PBPA commented that, "The proposed annual H_2S limit of 4.5 tons/yr (in Chapter 106) will greatly increase the number of facilities required to comply with the standard permitting process. These companies are presently covered by the existing TCEQ Permit by Rule."

M.E Operating and Services commented that, "The present VOC emission level for Level one b in the referenced proposal permit is 50 lbs/hr. The emissions vented from a tank filling with condensate is 56.8 lb/hr, according to TCEQ calculations shown in the proposed standard permit for OGS. If the level in Level on b could be raised to 60 lbs/hr, then an operator would be able to use Level on b emission levels instead of Level1c or Level 2. Level 1c or Level 2 requires an operator to obtain registration before construction. The formulas used to estimate emission levels of VOC from tank loading and flash losses of condensate are not accurate enough to prevent purchasing control equipment that might not be used when the well is put on line. If a well makes 20 barrels/day or less of condensate, the tank truck loading would only be weekly or less. The present rule makes any gas well that makes any amount of condensate obtain a permit before construction. The increase of the hourly VOC emission from 50 to 60 would not affect the health of the public, because tank truck loading would only be done weekly or less frequently. Please consider having a level for VOCs for sites more than 1/4 mile from a receptor, said sites producing 20 barrels/day or less of condensate."

The commission has changed the rule in response to this and similar comments. Most steady-state VOC emission limits for Level 2 are based on a distance of approximately 1/2 mile and uses all the same dispersion characteristics as Level 1.

TIPRO commented that, "Compressor engines often are not necessary during the initial months of production until pressure of the gas drops. However, sometimes level 2 dehydrator units are needed from the very first day of operation. As long as the hourly and yearly emission cap limits proposed on Level 1 post –construction registration are met, the type of process equipment that can be installed at the OGS should not be limited."

The commission has determined there is no reason to limit the types of facilities, controls, or operations for Level 1 as long as the maximum actual emissions after controls are less than the values now specified in subsection (g)(3).

Senator Davis commented that, "Ethylbenzene is missing from the list of substances (benzene, xylene, toulene) requiring monitoring for compliance with hourly and annual ESL for receptors within 2700 feet."

The commission has not changed the rule in response to this comment. The commission has evaluated all speciated VOC emissions, including HAPs and BTEX, and determined that benzene is the only contaminant which needs to be evaluated for each registration.

Weisman Engineering commented that, "The present VOC emission level for Level 2 in the referenced proposal permit is 50 lbs/hr. The emissions vented from a tank filling with condensate is 56.8 lb/hr, according to TCEQ calculations shown in the proposed standard permit for OGS. If the level in Level on b could be raised to 60 lbs/hr, then an operator would be able to use Level on b emission levels instead of Level1c or Level 2. Level one c or Level 2 requires an operator to obtain registration before construction. The formulas used to estimate emission levels of VOC from tank loading and flash losses of condensate are not accurate enough to prevent purchasing control equipment that might not be used when the well is put on line. If a well makes 20 barrels/day or less of condensate, the tank truck loading would only be weekly or less. The present rule makes any gas well that makes any amount of condensate obtain a permit before construction. The increase of the hourly VOC emission from 50 to 60 would not affect the health of the public, because tank truck loading would only be done weekly or less frequently. Please consider having a level for VOCs for sites more than 1/4 mile from a receptor, said sites producing 20 barrels/day or less of condensate."

The commission has changed the rule in response to this and similar comments. All steady-state VOC emission limits for Level 2 are based on a distance of approximately 1/2 mile and uses all the same dispersion characteristics as Level 1. In addition, notification and registration requirements have been changed to ensure adequate information at the agency, but not create economic delays.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Hourly emission limits for Level 2 should be based on typical release parameters such as: Process vents and blowdowns limits based on 30-foot process vent at a distance of 2700 feet; Tanks and truck loading limits based on a 20-foot tank at a distance of 2700 feet; Based on 20ft engine (>1000hp) at a distance of 2700 feet; Based on 40ft flare at a distance of 1 mile (5300 feet). Typical emissions are more accurately represented as natural gas rather than liquid condensate or oil. We propose to add the option of meeting a total natural gas hourly limit or a VOC hourly limit in addition to the annual VOC limit. VOC emissions based on a calculated Condensate Vapor Space ESL based on the TCEQ liquid speciation used in their Interim condensate ESL determination. The proposed value is insufficient for VRU maintenance, which happens only a few hours/year. The limit set at greater than two times the TCEQ proposed limits. Protectiveness is shown at emission rates of up to 3070 lb/hr for engines based on 20ft stack (>1000hp) at a distance of 1 mile (5300 feet)."

The commission has changed the rule in response to this and similar comments. All steady-state VOC emission limits for Level 2 are based on a distance of approximately 1/2 mile and uses all the same dispersion characteristics as Level 1.

EDF commented that they "support the inclusion of the 75 lb/hr VOC limit, along with other such limits on specific pollutants identified in the proposal. The TCEQ should not increase any of the proposed Level 2 emission thresholds in the final rule. We also reiterate our concern about H_2S emissions stated above regarding §106.352 (g) and urge the TCEQ to require sour gas facilities to meet a minimum setback distance of 1/4 mile and emissions limits for H_2S that are no less stringent than those required by the current PBR."

The commission has changed the rule in response to this and similar comments. All steady-state VOC emission limits for Level 2 are based on a distance of approximately 1/2 mile and uses all the same dispersion characteristics as Level 1. As stated previously, there is no definitive reason for the commission to maintain the 1/4 mile sour gas requirement.

The Sierra Club commented that the flexible nature of the permit hinders public understanding, and potentially enforcement of the limits at OGS.

The commission has revised various statements, requirements, and reorganized the PBR to enhance understanding and make the rule more understandable to all parties. It is inherent in the nature of the oil and gas industry to have a variety of equipment and materials, but the commission has confidence in the practically enforceable requirements of this rule.

Impacts Evaluation

EDF stated "We generally support all of the proposed exclusions in this subsection as these specialized sources should be authorized using separate source-specific requirements given their unique nature and the hazards that they pose. However, the TCEQ should clarify that emissions from the facilities, changes and activities not authorized under this subsection still need to be considered under §106.352 (b)(1)(B)(ii) to ensure aggregate emissions at an OGS are protective of public health and welfare."

The commission has not changed the rule in response to this comment. The sources that are excluded under subsection (d)(2) with no dependent PBR reference, and are operationally dependent to a group of oil and gas facilities are required to obtain a case-by-case state permit to authorize changes or a new site. The sources under subsection (d)(2) which have referenced PBRs may be co-located near oil and gas facilities under §106.352 must be included in the impacts review under subsection (k). Specifically, subsection (k)(5)(A)(iii) and (B)(ii) requires "all facility emissions, regardless of authorization type, located within 1/4 mile of a project requiring registration under this section shall be evaluated." Thus all relevant emissions from facilities are evaluated for protectiveness.

The commission appreciates the support of the minimum distance requirement. The commission strongly believes the need for some defined buffer requirement between an OGS and a nearby receptor.

Parrish Field Services commented that, "To the extent that TCEQ is convinced that minimum distance limits on receptors and/or the property line is necessary, NorTex endorses those included in the proposal. As was noted by the Sierra Club in the public meeting, cities have the option of adopting restrictions on the location of oil and gas facilities, so the 50-foot distance limit proposed by TCEQ may not be necessary. However, if the agency concludes that public health cannot be protected absent some minimum distance, the 50-foot distance is preferable to an attempt to match limits adopted by one city or the other."

The commission appreciates the support.

Senator Davis commented that, "The separation distance should be increased from 50 feet to 200 feet and 600 feet for new wells. This separation is more consistent with other states' regulations (New Mexico). A variance should be available to local government for modifications based on specific circumstances."

The Sierra Club and 134 individuals requested to increase the minimum separation to receptors from 50 to 250 feet. The Sierra Club also stated that "the distance is simply not sufficiently protective of public health and welfare."

TRAED and 5 individuals stated that, "Separation to receptors should be 250 feet and 500 feet would be better for the public."

Five individuals and Earthworks Texas Oil and Gas Accountability Project stated that, "Many municipalities have adopted 500-foot setbacks for industrial installations to protect their population. Industry has moved into the unincorporated areas to avoid these setbacks, and some of the oldest OGS are located next to residences and schools in these areas. TCEQ regulations are the only protection in these areas, and a 50-foot setback is not sufficient to provide protection from an OGS containing up to 40 pieces of equipment."

The commission has not changed the rule in response to this comment. Due to the unique nature of the oil and gas industry and the potential and historical location of various facilities, and based on the protectiveness review completed, the commission do not agree that 100 feet to 500-foot buffers are appropriate or necessary. Depending on the type and quantity of emissions released, distance limits for particular combinations of facilities are established by compliance with subsection (k). Local ordinances in cities and towns can establish greater distance limitations and have the option of adopting restrictions on the location of oil and gas facilities in their jurisdiction.

Representative Burnam opposes the 50-foot setback from receptors and states that TCEQ mobile monitoring found elevated levels of benzene (above long-term ESL) over 1,000 feet from an emission source. He proposes a minimum of 250 feet as a separation distance.

The commission has not changed the rule in response to this comment. The

protectiveness evaluation shows that certain facilities and releases, if small enough, are protective and acceptable at small distances. Although limited monitoring at a particular location may have shown elevated readings, that situation is not expected to occur and any new sites which obtain authorization under the new PBR requirements will be required to demonstrate how their emissions meet all guidelines and standards by complying with subsection (k) and other relevant limits in the PBR.

EDF commented that, "New OGS facilities should be no closer than 100 feet from any property line or receptor, instead of the proposed 50 feet to account for potential uncertainties in dispersion modeling at short distances under calm wind conditions."

The commission has not changed the rule in response to this comment. Treatment of calm or light and variable wind poses a special problem in model applications since steady-state Gaussian plume models assume that concentration is inversely proportional to wind speed. During conditions of calm winds, one would not expect pollutants to disperse over a large area. Generally, concentrations become unrealistically large when calm winds are input to the model. Procedures have been developed to prevent the occurrence of overly conservative concentration estimates during periods of calms. These procedures acknowledge that a steady-state Gaussian plume model does not apply during calm conditions. Model limitations were taken into consideration when determining the predicted concentrations at 50 feet. In order to account for potential uncertainties in

dispersion modeling at short distances under calm wind conditions, the results for all sources at 4,375 μg/m³ and occurs at the 100 feet receptor. Even though the model prediction for the 50 feet receptor was less than 4,375 μg/m³, the results listed in the table is 4,375 μg/m³.

Pioneer requested clarification in the rule or preamble on "whether movable engines meet the definition of "immovable," For instance, engines consist of multiple parts: the base or concrete pad the engine may sit on, the piping that connects to the engine, and the combustion portion of the engine. The concrete pad and piping are typically not movable and are part of the engine, whereas the engine itself may be easily swapped out with another engine. If the engine has a permanent concrete pad or piping, it should be considered immovable and therefore, an exception to the "50 feet from any property line or receptor" limitation."

The commission has added language to the rule to allow replacements of existing facilities within 50 feet of property lines and receptors. If the facility is modified or replaced, the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50-foot requirement. Replacement facilities must meet all other requirements of this section. Whether an engine is "movable" or "immovable" is not the basis for determining if an engine is "permanent." However, the commission will not grant a general exception to all facilities that are replacing previously authorized facilities that are located less than 50 feet from a property line or receptor. An operator must be able to demonstrate that good engineering practices would not allow the

replacement facility to be moved to meet the 50-foot set-back. Only after such a demonstration would the exception to the 50-foot set-back requirement apply to the replacement facility. The commission has a rule air rule interpretation summary memo that describes when an engine is considered a stationary source and needs an authorization. The memo states that "a portable or transportable engine which remains or will remain at a single point or location less than or equal to 12 consecutive months is not considered a stationary source and no authorization under 30 TAC Chapters 106 or 116 would be required." This rule interpretation memo may be revised in the future.

TPA stated that subsection (e)(3)(C) "That subsection should be struck in its entirety as it is unclear what would be required if the facilities were movable and unfixed. The provision basically establishes a 50-foot setback from any property line or receptor but states that it does not apply to, among other things, "existing, immovable, fixed OGS facilities which were constructed and previously authorized, even if modified." It sets up a question of fact as to whether facilities are movable or not without consideration to costs, engineering design and other factors. The provision over complicates what should be a simple authorization mechanism."

The commission respectfully declines to change this subsection in response to the comment. The commission will maintain guidance as to what is reasonably considered immovable. The commission agrees that a concrete pad and piping at a certain location would be considered immovable and replacement engines that do

not increase potential to emit are part of that existing, immovable, fixed OGS facility.

One individual stated that they "Recently filed an odor complaint with TCEQ regarding diesel exhaust emissions. The odor was so bad it required that he put his family in a motel for the evening. The report from TCEQ stated that "continuous operation of three diesel generators greater than 400 hp at this site resulted in significant emissions of nitrogen oxides. An estimate of maximum nitrogen oxide for one hour on a complainant's property using a screen model was 380 ppb. Aruba Petroleum should use nitrogen oxide controls on its diesel engines as his family was exposed to more than 10,000 years of nitrogen oxide in 2 months. Studies have shown that children on the Barnett Shale have an asthma rate of 25 percent versus a national average of 7 percent, and his daughter was recently diagnosed with the disease. He questions how many more will be diagnosed before TCEQ requires electric drills or diesel filters. Aruba has been found in violation of Title 30 and the THSC numerous times in the last year. He stated that TCEQ should not make it any easier on a bad operator than they obviously have it."

Applicants will be required to demonstrate that all engines on site will be protective of the NAAQS including NO_2. The current one hour NAAQS for NO_2 is 188 $\mu g/m^3$. Under the proposed rule, the company would have to show it does not cause an impact greater than the NAAQS at any off-site receptor. Diesel engines subject to the proposed rule will be required to meet current off-road engine standard which will reduce NO_X and particulate greatly compared to older engines

TPA commented that they have "the following technical revisions to the engines and turbines BMP. It believes that having met the federal requirements applicable to these units should satisfy the TCEQ as to the protectiveness of these facilities. A complete review and public participation process has been conducted to develop these federal standards with input from all stakeholders. The TCEQ should accept these as valid standards for a conceptually simple authorization. Accordingly, subsection (e)(4), related to engines and turbines, should be revised and Table 9 should be deleted except that the last section of Table 9 should be incorporated into subsection (e)(4)(A)."

Table 6 has been revised to eliminate emission standards for rich-burn engines less than 500 hp. It is the TCEQ's understanding that these engines are replaced frequently and would eventually be replaced with 40 CFR 60 NSPS Subpart JJJJ compliant engines in the next 10 years. Therefore, the TCEQ is not making a duplicative standard. Also, the only substantial change from the current §106.512 is that rich-burn engines greater than 500 hp must meet 1 gram NO_X/hp-hr by 2020 rather than the 2 grams NO_X/hp-hr in the current §106.512. While a portion of engines currently meet the proposed standard, the remaining engines will need to be upgraded. Since catalysts are replaced approximately every 10 years, industry is given until 2020 to upgrade so that future catalyst systems can be phased in as current controls reach their end of life. The TCEQ does not agree that federal rulemaking is a substitute for state rulemaking. The EPA only considered what was statutorily required for their rules and this differs from the statutory requirements of the TCAA.

TPA and ETC recommended changes to Table 9 in subsection (m) of this section to avoid duplicating applicable requirements of 40 CFR Part 60 and 40 CFR Part 63 stating that 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."

Table 6 has been revised to eliminate emission standards for rich-burn engines less than 500 hp. It is the TCEQ's understanding that these engines are replaced frequently and would eventually be replaced with 40 CFR 60 NSPS Subpart JJJJ compliant engines in the next 10 years. Therefore, the TCEQ is not making a duplicative standard. Also, the only substantial change from the current 512 is that rich-burn engines greater than 500 hp must meet 1 gram NO_X/hp-hr by 2020 rather than the 2 gram NO_X/hp-hr in the current 512. While a portion of engines currently meet the proposed standard, the remaining engines will need to be upgraded. Since catalysts are replaced approximately every 10 years, industry is given until 2020 to upgrade so that future catalyst systems can be phased in as current controls reach their end of life. The TCEQ does not agree that federal rulemaking is a substitute for state rulemaking. The EPA only considered what was statutorily required for their rules and this differs from the statutory requirements of the TCAA.

TIPRO commented that, "The costs associated with retrofitting tank batteries or constructing tanks where concrete ponds are currently used will cause small scale production to become sub-economic to operate. The commission should exempt tank batteries with throughput less than a *de minimis* levels, 10 barrels (for example). A stripper well is defined as one with less that 10 barrels of oil per day and may provide a potential *de minimis* level."

The PBR establishes a *de minimis* for open-topped tanks or ponds containing VOCs or H_2S up to a PTE equal to 1 tpy of VOC and 0.1 tpy of H_2S. If in fact open-topped tanks or ponds are absent of VOC and H_2S emissions as so often represented by the Oil and Gas industry this *de minimis* level should be sufficient. The commission has changed the rule in response to this and similar comments. Based on additional information submitted, field visits by agency staff, and further research on smaller combinations of facilities, the commission has added subsection (c)(4) to further streamline authorizations and appropriately focus agency and industry resources.

Representative Burnam stated his strong support for “the requirement for applicants to complete a health and welfare protectiveness review to ensure that emissions from all oil and gas sites are consistent with ambient air standards and effects screening levels for relevant hazardous air pollutants.” He also stated that “limiting individual emissions sources to the lower of those derived from the site-wide caps and those determined by the protectivness review is an essential provision of the rule and should not be removed or weakened in any way.” He also supports “the target efficiency built into the rule by allowing emissions limits to vary with distance to the nearest recepetor.”

The commission appreciates the support and agrees that any PBR or standard

permit must be protective of public health and welfare.

EDF disagreed with "TCEQ's assertion in the preamble that the proposed "site-wide perspective" satisfies EPA requirements and agreements to assess cumulative air quality effects from related, similar sources. (See 35 TexReg 6943). The TCEQ should clarify what cumulative air quality effects were assessed and on what basis they were deemed to be acceptable."

EPA stated that “the federal Clean Air Act requires that state SIP permitting programs regulate the construction and modification of sources to achieve and maintain compliance with the NAAQS and PSD increments and that SIPs include provisions prohibiting any source that will emit pollutants that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS. Because the proposed PBR and standard permit could be used to authorize thousands of sources, many of which are in, near, and/or upwind of ozone nonattainrnent areas, TCEQ should provide a demonstration that the cumulative use of PBRs and standard permits will not authorize sources that in the aggregate will cause or contribute to nonattainment or violations of the PSD increments. As EPA issues the new lower 8-hour ozone standard, more areas in Texas will be nonattainment and likely be impacted by the cumulative effect of sources permitted by PBR or standard permit, and the cumulative impacts could exacerbate the ozone levels. Study of the growth of sources in the Barnett Shale should serve as a good template to compare with how other areas could also grow for evaluation of the impact of sources permitted by the PBR or standard permit.

The commission continues to assert that the proposed site-wide perspective

satisfies EPA requirements and agreements to assess cumulative air quality effects from dependent, similar sources. The commission clarifies for the commenter that the protectiveness review for this rulemaking was conducted under TCAA and TCEQ rules. The TCEQ evaluated EPA-regulated pollutants under the minor NSR program. EPA has not promulgated any rules that specify minor NSR requirements. The commission followed major source rules and guidance relating to major source and existing major source modifications. However, since TCEQ prohibits new major projects or major project modifications under this rulemaking, no major source protectiveness review rules or guidance apply. The commission balanced overall environmental benefit and economic development to address concerns related to potential cumulative air quality effects. The commission based its evaluation on conservative operational and modeling scenarios and general assumptions used to develop the Industrial Source Complex model. The commission used predicted maximum hourly modeling concentrations to set hourly and annual emission caps and to evaluate impacts to ensure that state and national standards and ESLs would be met. Therefore, the protectiveness review was deemed acceptable.

TXOGA commented that, "As currently proposed, §106.352(b)(5)(B) of the Proposed PBR would subject existing, non-modified facilities at an OGS (i.e., those facilities whose character of emissions will not change and quantity of emissions will not increase) to the requirements of §106.352(b)(6) of the Proposed PBR. Subjecting existing, non-modified facilities to subsection (b)(6) would have the effect of retroactively imposing regulatory requirements on existing facilities. TCEQ correctly concludes in the preamble discussion of the Proposed PBR and the

"Permit Conditions and Analysis and Justification" section of the Proposed Standard Permit that Article 1, Section 16 of the Texas Constitution, §311.022 of the Texas Government Code, and case law (e.g., All Saints Health System v. Texas Workers' Compensation Commission. S.W.3d 96, 104 (Tex.App. - Austin 2003, pet. denied)) require that the Proposed PBR and Proposed Standard Permit "not be applied retroactively," and that they only be applied to "those facilities that are either newly constructed or modified" after the Proposed PBR becomes effective. However, as written, Subsection (b)(5)(B) would be counter to the TCEQ's correct conclusion regarding retroactivity. This is because Subsection (b)(5)(B) would impose the requirements of Subsection (b)(6) on existing, non-modified facilities, rather than only to facilities that are "either newly constructed or modified" after the effective date of the Proposed PBR. For the Proposed PBR to not violate the constitutional, statutory, and case law prohibition on retroactive application of regulatory requirements, Proposed §106.352(b)(5)(B) must be revised to read as indicated in Exhibit 3."

Devon expressed concerns about "air quality and health effects from Barnett Shale OGS emissions in the Dallas-Ft. Worth (DFW) area appear to provide at least part of the rationale for TCEQ's proposed PBR and standard permit. However, as discussed in more detail in TXOGA's comments, the reputable air sampling activities and studies performed to date in the DFW area, including air sampling performed by the TCEQ, consistently indicate that: (i) OGS are not the primary source of benzene in the DFW area; (ii) benzene, toluene and other volatile organic compound (VOC) emissions from Barnett Shale OGS are below levels that would raise health or welfare concerns, and (iii) Barnett Shale OGS emissions have a negligible impact on ambient air quality in the DFW area. In light of the results of this air quality information and data, the TCEQ would appear to lack, and has not yet articulated, the "reasoned justification" for its extremely prescriptive, detailed and onerous proposed PBR and standard permit that is required by Texas Administrative Procedures Act (TAPA) §2001.033."

Kinder Morgan commented "The proposed modeling requirements in Subsection (b)(6) exceed federal NSR/PSD requirements. Subsection (b)(6) should be revised so that impacts reviews will only be required for new or modified sources. Stated otherwise, an impacts review would only be required for the project emissions as is required under federal major source NSR/PSD requirements. This revision would establish modeling protocols for the proposed PBR and standard permit consistent with federal NSR/PSD requirements. In addition, modeling should be required only if the projected affected emissions exceed the thresholds in (k)(3)(B). In addition, subsection (b)(5)(B) subjects unchanged facilities to an impacts review and modeling demonstrations typically reserved only for facilities that are part of a project. Under federal NSR/PSD regulations, unchanged or unmodified sources at a site are not considered part of a project, are not required to be included in an impacts review, and are not required to demonstrate compliance with a NAAQS. Accordingly, by subjecting existing, unmodified facilities at a site to these demonstrations, the TCEQ is being stricter with its minor source program than federal major source permitting."

TPA commented that, "There are provisions in the proposed OGS PBR that would impose requirements stricter than those imposed by federal law and/or under federal major source permits. This is inappropriate, inasmuch as the PBR would apply to insignificant sources many of which will be located in rural attainment areas. Nonetheless, it appears that the revised PBR is more stringent than federal requirements and major source permits in the following important respects. First, the modeling analysis or impacts review that is required to be performed under proposed §106.352(b)(6) requires the inclusion of the emissions of both new and modified sources as well as existing unmodified sources. Under the PBR, even "non-project-related" existing unmodified facilities will be required to be included in the impacts analysis for the new project. The federal PSD/NSR permit modeling requires modeling only for those pollutants that exceed major source thresholds (e.g., 40 tpy for NO_X for a major modification) for the project-affected sources. Modeling is not required for those pollutants where the increases do not exceed the major source thresholds. The modeling itself is a two-step process: first, only the project-affected sources are modeled, and if their impact is within acceptable thresholds, no additional modeling is required. A more comprehensive modeling including additional sources is only required if the impact from project-affected sources is beyond acceptable thresholds. The revised PBR, however, establishes emission thresholds beyond which modeling is required for the entire OGS, not just the new or modified equipment. Furthermore, modeling is also to be performed for all facilities at the OGS within Y4 mile regardless of whether or not the facilities are modified. Thus, in both aspects the PBR's modeling requirements appear to be conceptually more stringent than are the federal PSD requirements. In addition, the result of impacts analysis under the proposed PBR could drive controls to an existing unchanged facility that is located as far as 1/4 mile from the project itself. This in and of itself is stricter than federal PSD/NSR, which does not require facilities that are not part of a project to be modified."

The City of Fort Worth commented that "the proposed rules rely heavily on dispersion as a method to reduce the impact of HAP on communities and much of the rule allows permittees to raise their stack or vent heights to as much as 60 feet to disperse HAP concentrations at the nearest receptor as based upon back-calculation from computer models. Although this appears to be a valuable method for minimizing impacts it should only be used as a "last resort" methodology, after appropriate emission controls have been installed at all significant emission points. Allowing uncontrolled emissions from tanks and then using high stacks to disperse those uncontrolled HAP emissions just cause the air contaminents to pollute a larger area albeit a lower theortetical concentration. In addition, dispersion depends on favorable meteorological conditions and temperature inversions for example would nullify the effectiveness of the hypothetical dispersion. In addition, there will be an incentive for permittees to raise stack heights which could result in unintended consequences such as air traffic safety problems particulary near airports, heliports, and flight paths. Excessive stack heights may also be visually intrusive and may conflict with municipal ordinances."

The commission has not changed the rule in response to this comment. The rule as adopted does not directly impose any specific control requirement on existing, unchanged, previously authorized facilities. The rule does require projects to be evaluated for their potential contribution to ambient air quality and protection of public health and welfare. If the emission impacts from a project at a site are greater than small portions of standards or ESLs, then a site-wide impacts evaluation is needed. An impacts evaluation must show that the project, and other sources on a site, must ensure compliance with NAAQS and meet ESL guidelines. The outcome of this evaluation may require applicants to change the proposed project, or choose to make other changes at the site in order to proceed with a project, before an authorization is issued. The requirements of the rule are consistent with all minor NSR permit reviews technical analysis as well as

standardized PBR and standard permit rule adoption reasoned justifications. Additionally, any control option chosen by an operator cannot conflict with local or federal law, including laws concerning maximum height of obstructions in the vicinity of an airport.

Kinder Morgan suggested the "TCEQ should revise the PBR such that if a project is not located within 2700 feet of a receptor, no evaluation of emissions will be required and the emissions limits for these units will be the standard 25/250 for PBR facilities. The justification for requiring an evaluation of emissions for only those projects within 2700 feet of a receptor is, as stated by Commission staff in the preamble: "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 percent mile." Therefore, no evaluation should be required for projects that are not within 2700 feet of a receptor."

The commission has changed the rule in response to this and similar comments. The adopted rule provides exceptions for completing a site-specific ESL impacts evaluation if there are no receptors with 1/4 mile (Level 1) or 1/2 mile (Level 2) distances which were used to establish the emission limits. The adopted rule provides exceptions for completing a site-specific AAQS impacts evaluation if there are no property boundaries with 1/4 mile (Level 1) or 1/2 mile (Level 2) distances which were used to establish the emission limits.

EDF note that the "EPA Guideline on Air Quality Models published in 40 CFR 51, Appendix W does not list ISCST3 as a preferred air quality model for use in regulatory applications. Furthermore the EPA's SCRAM website states the following: As of December 9, 2006, AERMOD is fully promulgated as a replacement to ISC3, in accordance with Appendix W." Because ISCST3 is not a recognized model by EPA, ISCST3 should not be used to evaluate impacts from sources subject to federal review. If the modeling conducted for the proposed OGS PBR and standard permit is performed using ISCST3, the resulting PBR and standard permit should not be used to authorize facilities at sites that are a major source of air pollutants or any other source subject to federal review."

AERMOD is EPA's preferred model for major NSR; that is, those new major sources or major modifications to existing major sources that trigger federal review. Since the Oil and Gas projects authorized under PBR or standard permit cannot be major, the commission used the ISCST3 model (ISC) to conduct the protectiveness review. The commission uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site.

AERMOD was developed to address complex atmospheric processes in a more

refined way but the basis of the model and associated pre-processors and meteorology are not easily understood. Unlike ISC which has been vetted and improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them.

In addition, AERMOD is unnecessarily complex for general use. Since the protectiveness review for the PBR/standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air soundings and values for surface characteristics such as roughness length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but must be estimated.

The values for these characteristics vary with location and time of year. To account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most representative coefficient.

EDF commented "to ensure that the truly "worst-case" scenario for all sources has been considered, at least for Table 2 and Table 6 sources, the TCEQ should run both ISCST3 and

AERMOD with met data from multiple locations in the state (perhaps one county in each TCEQ region). For a given source category, the TCEQ should choose the highest prediction from all modeling runs for the values in Tables 2-6."

The commission developed reasonable and not absolute "worst-case" operational and meteorological scenarios. The commission did not use a screening meteorology dataset based on the wind speed and stability categories used in the SCREEN model because it includes some combinations of stability class and wind speed that are not considered standard stability class/wind speed combinations, such as stability class E with winds less than 2 meters/second (m/s), and F with winds greater than 3 m/s. The combinations of E and winds of 1 - 1.5 m/s are often excluded because the algorithm developed by Turner to determine stability class from routine National Weather Service (NWS) observations excludes cases of E stability for wind speeds less than 4 knots (2 m/s). There might appear in a data set of on-site meteorological data with another stability class method but use of these data sets is not expected for this PBR or standard permit.

The protectiveness review used meteorological data obtained from a single area. The data were quality assured following EPA guidance to fill in missing data; adjust low mixing heights; and adjust wind speeds to account for reported calms and differences in values due to various raw meteorological data sources (SAMSON and HUSWO).

Because only a single set was used, the commission used 5 years of data and adjusted the hourly wind directions to coincide with each 10 degree interval on a 360 degree polar grid (starting at 10 degrees and ending at 360 degrees); that is, the EPA randomness factor was removed. Theoretically, this adjustment should provide impacts at a receptor that reflect worst-case meteorological conditions, since the plume centerline intersects the receptor directly.

One would not expect predictions from AERMOD and ISC to be identical. Adjustments made to the meteorology used by ISC were based on the underlying assumptions of the model and how input data are used to calculate concentrations. AERMOD has different underlying assumptions so direct comparisons are not appropriate for this type of review. The meteorology used in AERMOD is much more complex than the meteorology used in ISCST3; particularly surface roughness, Bowen Ratio, and albedo. While EPA recommends that meteorological data used in AERMOD should be spatially and temporally representative of the modeling domain, only one value can be entered into the meteorological processor. Thus the commission has characterized modeling using AERMOD as refined screening when it's used in the permitting process.

TPA urges the "TCEQ to modify subparts (b)(5)(B) and (b)(6) prior to adoption to provide that an impacts review will only be required for new sources or sources that are increasing emissions. Stated otherwise, an impacts review would only be required for the project emissions. Otherwise the modeling requirement for all sources at the OGS within 1/4 mile regardless of modification makes it potentially more stringent than the federal NSR/PSD requirements. TPA supports the emission thresholds in (k)(3)(b) beyond which modeling is required and suggests that these thresholds be applied only to the project-affected sources rather than the combined emissions from the OGS. Additional edits to the introductory clause of subsection (b)(5) are needed to improve clarity. Not all facilities have certified emissions so TPA recommends the revision to this phrasing. (b)(5) For purposes of determining applicability claim or registration under this section, the following provisions apply: (B) Notwithstanding any other provision in this section, existing authorized facilities, or group of facilities, at an OGS under this section which are not changing the certified character or increasing the quantity of emissions must only meet paragraph (6) of this subsection and subsection (i) of this section. The combined effect of Subsections (b)(5)(B) and (6) is that emissions from all facilities at an OGS must be included in an impacts review conducted under subsection (b)(6) even if those facilities are not increasing emissions or increasing their potential to emit. Depending on the modeling results, controls may be required on these otherwise unmodified or unchanged sources. This outcome contradicts the PBR's accompanying Executive Summary, which states that "{o}il and gas facilities currently authorized under a PBR and that remain unmodified are not affected by this proposal except for identifying notification and planned MSS." This is simply not the case. Moreover, these unchanged facilities will be required to meet new NAAQS standards that are promulgated long after the facilities are constructed. Not even federal major source permitting standards demand this demonstration of existing, unmodified sources. The TCEQ is requiring this demonstration to be made by existing, unmodified, minor, insignificant sources. A PBR is the simplest form of NSR permitting for the state of Texas, and the modeling exercise should reflect this. A PBR should not contain more stringent procedural requirements than those associated with modeling for PSD permits."

The commission has changed the rule in response to this comment. The impacts analysis is only required per subsection (b)(8) if a project has an increase in a particular air contaminant. Additionally, subsection (k) emphasizes that impacts reviews are on an individual contaminant basis. The commission has also added options to evaluate project-only increases if they contribute only a small amount of an ESLs or ambient air standard. Only if project increases are greater than these amounts are all source contributions within a 1/4 mile of the project are considered to ensure the operations will continue to comply and be protective after the project is implemented.

ETC commented that, "The impacts review provisions of subsection (b)(6) should be revised. Consistent with the suggested changes to subsection (b)(5)(B), ETC suggests that subsection (b)(6) of the proposed PBR and Standard Permit be revised to provide that impacts reviews will only be required for new sources or sources that are increasing emissions. We also suggest that the subsection be revised to provide that, if a project is not located within 2700 feet of a receptor, no evaluation of emissions will be required and the emissions limits for these units will be the standard 25/250 for PBR facilities. The justification for requiring an evaluation of emissions for only those projects within 2700 feet of a receptor is, as stated by Commission staff in the PBR preamble, that "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." Therefore, no evaluation should be required for projects that are not within 2700 feet of a receptor."

The commission has changed the rule in response to portions of this comment. The rule has been updated to not require an impacts review if a property line or receptor is not with a 1/4 mile (Level 1) or 1/2 mile (Level 2), depending on the air contaminant. These distances are equivalent to the distances used on the modeling tables to establish the hourly emission limits for the PBR levels as specified in subsections (g) and (h). The commission has also changed the rule to only require an impacts analysis if a project has an increase in a particular air contaminant. The commission has also added options to evaluate project-only increases if they contribute only a small amount of an ESLs or ambient air standard. Only if project increases are greater than these amounts are all source contributions within a 1/4 mile of the project are considered to ensure the operations will continue to comply and be protective after the project is implemented. The commission has not changed the rule in response to the comment to have no hourly emission limits and rely exclusively on the general requirements for PBRs (25 / 250 tpy limits of §106.4). The commission's review has clearly shown that limits must be established to demonstrate that this standardized authorization mechanism will be protective and comply with ambient standards.

TPA commented that, "The modeling or impacts analysis of proposed §106.352(b)(6) essentially requires a retroactive demonstration of compliance with any NAAQS by existing and unmodified sources. Under this provision, sources that would have to make this demonstration include not only the new and modified sources in the project requiring registration under the new PBR, but also any unchanged and existing facilities within 1/4 mile of the project. This standard is stricter than federal PSD in that under the federal PSD program only new major facilities or major modifications must meet this demonstration. 42 U nited States Code §7475. In the case of the proposed PBR, this demonstration is being imposed on old, unchanged, minor, insignificant facilities — a standard much stricter than any federal major source standard."

The commission has not changed the rule in response to this comment. The rule as adopted is consistent with minor NSR permitting and published ESL modeling guidance. In the circumstances where all contributing sources are considered as a part of the impacts evaluation, this scope is necessary to ensure the operations will continue to comply and be protective after the project is implemented.

Conoco Phillips suggested that the following with respect to Scope of Impacts Analysis: "a) Protectiveness analysis should not be necessary if no receptors exist within 1/2 mile of the project. b) Determination of impact for NAAQS should also be done at receptor locations rather than property line similar to that done for ESLs. c) Allowances should be made for modeling impacts of intermittent and infrequent sources such as loading and other MSS activities that do not occur on a continuous basis."

TPA commented that, "If modeling is required, it should be a two-step process: 1) model only any sources that are associated with the project and evaluate impact on the receptor; 2) if the predicted project impacts exceed the ESLs or the standards, or if necessary, a fraction such as 50 percent of the ESLs or standards, perform additional modeling to better understand the situation by including facilities within 1/4 mile of the project. This is generally consistent with the requirements for other permit programs including the PSD major source program."

The commission has also changed the rule to only require an impacts analysis if a project has an increase in a particular air contaminant. The commission has also added options to evaluate project-only increases if they contribute only a small amount of ESLs or ambient air standard. Specifically, of any given project is equal to or less than 10 percent of an ESL, any combination of projects are less than 25 percent of the ESL, and if any project is equal to or less than the SIL. Only if project increases are greater than these amounts are all source contributions within a 1/4 mile of the project are considered to ensure the operations will continue to comply and be protective after the project is implemented.

TPA commented that, "A mechanism needs to be developed to address short-term exceedances of ESLs during loading or MSS activities. Currently, MSS activities, loading, and other short-term activities are subject to impacts reviews. Staff has recognized that these types of activities need to be addressed separately rather than through the traditional modeling addressed in subsection (b)(6). TPA would urge the TCEQ to do so. As an example, emissions from activities that occur only 10 percent of the time or 1,000 hours per year should not be considered on par with emissions from continuously occurring activities. It is economically infeasible to install controls that would only be required to address emissions from activities that occur intermittently such as loading or some MSS activities."

The commission has changed the rule in response to this and similar comments. In recognition of the periodic higher emissions, the commission has established more appropriate emission limits for these occasional releases which are also protective.

An individual commented that, "It is a mistake not to consider the ambient air quality surrounding each facility. Exposing facilities located in areas high air quality, to the same degree of oversight and regulations as those located in nonattainment areas, is simply going to overburden TCEQ's resources as we move into the future."

The commission has not changed the rule in response to this comment. The evaluation of source types, character and quantity of expected emissions, dispersion of releases, and predicted impacts is consistent with all air quality evaluations for minor sources throughout the state. In nonattainment areas, sources are also subject to additional requirements under 30 TAC Chapters 115 and 117 to address unique air quality issues in those areas.

EPA stated that the "TCEQ should discuss modeling assumptions that will ensure compliance with the NAAQS. Examples of assumptions which should be discussed include the estimated number of facilities expected to be covered under this permit as well as their assumed locations (i.e., identify potentially high density locations). TCEQ has indicated that 11,000 OGS claim the current oil and gas PBR. Has TCEQ considered the cumulative impacts from numerous PBR and standard permits in certain regions and statewide and the NAAQS? Does TCEQ have a mechanism for identifying and tracking sources operating under the current oil and gas PBR and the old standard exemption? Has TCEQ evaluated how sites operating under the PBR will affect the NAAQS? The public record for the initial issuance and any subsequent revisions of the Standard Permit that the oil & gas sites which are subject to this Standard Permit or PBR should clearly detail that the permits will not violate the SIP-approved control strategy and does not interfere with attainment and maintenance of any air quality standard (see 40 CFR 51.160(a) and 51.161(a)."

Specific and extensive details of the emission impact analysis are provided in both the SECTION BY SECTION DISCUSSION of this document as well as the STANDARD PERMIT FOR OIL AND GAS PRODUCTON FACILITIES BACKGROUND document. The rule as adopted is consistent with minor NSR permitting and published ESL guidance. The reasoned justification and resulting rule requirements use reasonably conservative assumptions. Each authorization with property lines in close proximity will be required to demonstrate compliance with NAAQS. Additionally the rules clearly state that all authorizations must comply with all SIP-approved control strategies as promulgated in 30 TAC Chapters 115 and 117.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented that the "Protectiveness Review section of the Proposed Standard Permit36 does not provide adequate technical support for the Proposed PBR and the Proposed Standard Permit. TCEQ infers that OGS could be authorized under the current PBR and standard permit yet still exceed some limits such as short-term

ESLSs and the CO_2 NAAQS. TCEQ does not, however, explicitly document any alleged shortcomings of the current PBR and the current standard permit. Although TCEQ used information from actual applications and registrations to frame the protectiveness review, TCEQ did not perform protectiveness reviews of actual sites. Further, even though it is evident that the Proposed PBR and Proposed Standard Permit would address protectiveness at a higher level than the existing PBR and existing standard permit, TCEQ has offered no reasoned justification why the current PBR and the current standard permit are not sufficiently protective. In addition, even if TCEQ has adequately supported that the protectiveness of the existing PBR and the existing standard permit should be increased (which TXOGA disputes), this in no way provides a reasoned justification for the extraordinarily stringent and excessive new requirements that have been placed in the Proposed PBR and Proposed Standard Permit. As previously stated, TCEQ is not afforded a presumption that a reasoned justification (i.e. factual basis) exists to support the Proposed Rulemakings. Put another way, TCEQ is not allowed to shift the burden of proof to regulated entities and the public to demonstrate that there is not a reasoned justification to support the Proposed Rulemakings. The above-discussed air quality monitoring and toxicological studies show that public health is not negatively impacted by emissions from OGS being operated under TCEQ's existing PBR §106.352 or standard permit for OGS in §116.620. TCEQ's own air quality monitoring and toxicological studies of emissions from OGS in the Barnett Shale contradict the protectiveness review that TCEQ cites as the apparent reasoned justification for the Proposed Rulemakings, and in fact, such studies show that there is not a protectiveness issue with the existing PBR §106.352 or standard permit for OGS in §116.620. Thus, TXOGA contends that the Proposed Rulemakings are arbitrary and capricious and should not be adopted in their current form. The Proposed Rulemakings must have an adequate "reasoned justification,"28 which expressly includes "a summary of the factual basis for the rule as adopted which demonstrates a rational connection between the factual basis for the rule and the rule as adopted."29 Portions of the Proposed Rulemakings would violate those statutory requirements if the TCEQ proceeds with adopting them as they are written. The Third Court of Appeals of Texas recently stated that it "review(s) a reasoned justification under an arbitrary and capricious standard, with no presumption that facts exist to support the agency's order." (emphasis added) In addition, an agency "acts arbitrarily if in making a decision it: 1) omits from its consideration a factor that the Legislature intended the Commission to consider; 2) includes in its consideration an irrelevant factor; or 3) reaches a completely unreasonable result after weighing only relevant factors." In the *Texas Register* notices, TCEQ repeatedly states that the Proposed Rulemakings (including the proposed repeal of the existing standard permit) are intended to ensure emissions from OGS are protective of public health and welfare, ensure protectiveness, or update the authorizations based on current scientific information. TCEQ states that it distributed a preliminary proposal for OGS in 2006 based on then current science, and that it was determined that additional, detailed information was needed to ensure a more comprehensive and representative review of facilities, controls and emissions associated with an OGS. TCEQ has purportedly based the Proposed Rulemakings on research that has continued for several years. The details of TCEQ's evaluation (sources, operations, controls, emissions, applicable state and federal regulations, and potential impacts/protectiveness review) are purportedly included in the Proposed Standard Permit. TXOGA assumes that such information is TCEQ's "reasoned justification" for the Proposed Rulemakings."

Specific and extensive details of the emission impact analysis are provided in both the SECTION BY SECTION DISCUSSION of this document as well as the

STANDARD PERMIT FOR OIL AND GAS PRODUCTON FACILITIES BACKGROUND document. The rule as adopted is consistent with minor NSR permitting and published ESL guidance. The reasoned justification and resulting rule requirements use reasonably conservative assumptions. The commission has also gathered numerous examples of registered OGS under the previous PBR §106.352 which show that there may be protectiveness concerns if these releases impact nearby receptors.

The Sierra Club and two individuals commented that the "proposed permits need to be more protective of public health, particularly for those living or working in close proximity to OGS."

One individual commented that, "TCEQ's ensuring that the proposed permitting scheme is sufficiently protective of neighboring populations and does not contribute to further degradation of air quality in or near nonattainment areas."

Mayor Tillman "applauds TCEQ for taking the action to propose new regulations. The town of DISH has a large concentration of oil and gas facilities nearby under 5 different permits by rule. Equipment includes 12 natural gas compressors, 3 dehydration units, and a number of condensate tanks. Any rules adopted should be easy to enforce. The town of DISH performed a comprehensive air study that showed concerns, and TCEQ seemed unprepared to take action. He believes there have been clear violations in DISH and has asked for specific tests for things such as formaldehyde which produced a "deer in the headlight look." There must be the motivation and expertise to enforce any new regulation. Around the country, the industry brags about the lax enforcement in Texas. Industry should be supported, but there are limits."

The commission has carefully considered all comments and concerns regarding the evaluation of potential impacts from oil and gas facilities. Specific responses to model selection, meteorological inputs, simulation of engine emissions, definition of receptor, required distances, and downwash issues are included in this document. Each authorization with property lines in close proximity will be required to demonstrate compliance with NAAQS. Additionally, the rules clearly state that all authorizations must comply with all SIP-approved control strategies as promulgated in 30 TAC Chapters 115 and 117. The adopted rule specifically requires an impacts analysis for any receptor in close proximity to any proposed oil and gas facilities or group of facilities.

Exterran "supports TCEQ's current formaldehyde impacts analysis in the Oil and Gas Proposal. As TCEQ established in the preamble to the Oil and Gas Proposal, the low levels of formaldehyde emissions from engine registration data do not warrant an additional formaldehyde impacts review for smaller OGS authorized by a PBR or Standard Permit. The agency's proposed approach and registration data review is supported by OEM not to exceed, or upper limit estimates of uncontrolled formaldehyde emissions from SI RICE and actual formaldehyde testing from SI RICE. Both the OEM data and the recent test data confirms TCEQ's review of the registration data and associated impacts assumptions. Recommendation: Taken together, the OEM uncontrolled emission data, additional SI RICE formaldehyde testing, and stringent federal standards focused on formaldehyde emissions from SI RICE strongly support TCEQ's Oil and Gas Proposal that recognizes the low formaldehyde emissions from SI RICE. The final Oil and Gas rule should not impose additional modeling requirements or duplicating existing federal standards and costly testing requirements. These items are discussed in more detail below. The OEM uncontrolled emission data in Attachment D-1 supports TCEQ's conclusion that for engines less than 1,000 hp, formaldehyde emissions are less than .57 lb/hr and for engines greater than 1,000 hp formaldehyde emissions are less than 1.15 lb/hr. Therefore, as modeled by TCEQ, SI RICE will not exceed the ESL hourly impacts for even the most conservative scenarios. The upper limit, not to exceed OEM data demonstrates that even in the most conservative emission estimates prepared by engine manufactures formaldehyde emissions from SI RICE remain extremely low. In addition to the NO and NO_2 monitoring data submitted on June 7, 2010, Exterran will be submitting formaldehyde test data for TCEQ's consideration under separate cover."

The commission has re-evaluated formaldehyde based on comments received and has revised the rule to not require a specific demonstration for acceptable impacts. The commission also concurs with the commenter that the quantification of formaldehyde emissions may rely on manufacturer's or vendor testing of typical units and that this information is sufficient to demonstrate compliance with the SI RICE 40 CFR 63 MACT.

Pioneer recommended that, "Air monitoring be included as an alternative method to modeling in order to demonstrate protectiveness for operators who choose to install monitors to gather accurate, real-time data."

Considerations for ambient air monitoring to demonstrate protectiveness was evaluated by the commission. To properly place the necessary number of monitors, quality assure all data, establish sufficient time to obtain data, create contingency plans if readings are not obtained, cost of monitors, and potential EPA involvement in any results obtained, all would require substantial commission and company resources, for minimal expected gain. The commission has not changed the rule in response to this comment. If monitoring is an option which an applicant desires to pursue, case-by-case NSR permitting is the appropriate mechanism.

Conoco Phillips is "requesting the following changes as it relates to the Scope of Protectiveness. The basis of the look up tables should be reviewed and revised consistent with the comments made by TXOGA and TPA. b) Modeling should be required only if he project affected sources exceed the thresholds in subsection (k)(3)(B). c) Modeling should be performed only for the project affected sources. d) If protectiveness analysis involving the project affected sources only is not deemed adequate, and additional protective analysis for existing sources is necessary, it should be done as part of a two step process. First step should be for the project affected increases. If the impact from the project affected sources exceeds a factor such as 50 percent of the ambient standards or ESL thresholds then a more expanded analysis involving other sources within 1/4 mile at the site should be conducted. e) No formal lb/hr limits should be assigned to facilities at the PBR. Only long-term TPY limits should be applicable."

The commission has changed portions of the rule in response to this and similar comments. The basis of the source Tables (2) - (5F) have been revised and confirmed to be appropriate and reasonably conservative. Impacts analysis is only required if project-specific pollutant increases are greater than values established as the lowest at which no adverse impact would be expected at the closest distance.

Considerations for ambient air monitoring to demonstrate protectiveness was evaluated by the commission. To properly place the necessary number of monitors, quality assure all data, establish sufficient time to obtain data, create contingency plans if readings are not obtained, cost of monitors, and potential EPA involvement in any results obtained, all would require substantial commission and company resources, for minimal expected gain. The commission has not changed the rule in response to this comment. If monitoring is an option which an applicant desires to pursue, case-by-case NSR permitting is the appropriate mechanism.

Conoco Phillips is "requesting the following changes as it relates to the Scope of Protectiveness. The basis of the look up tables should be reviewed and revised consistent with the comments made by TxOGA and TPA."

The commission has updated the rule to require impacts analysis only for the project-specific pollutant increases if the resulting concentrations are less than or equal to 10 percent of ESLs or SIL guidance for ambient air standards. Subsection

(d) now reads, "Only in circumstances where project increases are greater than a portion of ESL or ambient air standards are other contributing sources under the same control, at the same property, with similar emissions, and within 1/4 mile must be considered."

Representative Burnam approves of effects review including facilities within 1/4 mile of the facility being authorized, but is concerned that facilities or sites within 1/4 mile of a receptor would not be considered as part of the protectiveness review. He also is concerned that 1/4 mile may not be sufficient in all circumstances and references EDF modeling and comments on the 1/4 mile inclusion. Representative Burnam encourages the commission to look beyond the 1/4 mile and consider facilities that may not be under common ownership and control.

Senator Davis recommended the "TCEQ should scientifically re-evaluate whether effects review of facilities within 1/4 mile is adequate to protect public health. A company should not be able to count facilities in the same area as two different sites. This would affect (b)(5)(C) as well."

The commission emphasizes that unless emission increases are so small as to meet the lowest acceptable emission impact at 50 feet, all projects must complete a contaminant-by-contaminant impacts evaluation for any receptor within 1/4 mile for the smallest of the PBR authorizations. The commission did carefully evaluate the requirements for larger emission releases and determined that an impacts review needs to be performed for any receptor within 1/2 mile to ensure protectiveness.

EDF commented that, "The pollutants covered under this section should also include CO, PM_{10}, $PM_{2.5}$ and formaldehyde."

The Sierra Club and two individuals stated that the "TCEQ should ensure that the new PBR and standard permit do not interfere with attainment of national ambient air quality standards (NAAQS). They also commented that the proposed permits must ensure that OGS do not circumvent major source requirements or interfere with attainment of the NAAQs."

The commission agrees with this comment and has adopted the new PBR with clear expectations of compliance demonstration with the NO_2 and SO_2 NAAQS. The protectiveness analysis for CO, PM_{10} and $PM_{2.5}$ shows that if emission limits as included in the rule are met, no additional demonstration is needed.

ETC recommended changes to subsection (b), "If a project is within 2,700 feet of a receptor: (i) Regardless of the emission limits established in subsection (b)(5)(D), hourly and annual emissions shall be limited based on the most stringent of subsections (g), (h), or (k) of this section; (ii) Compliance with ambient air standards shall be demonstrated for any receptor 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; and (iii) Compliance with hourly and annual effects screening levels (ESL) for benzene, toluene, and xylene shall be demonstrated at the nearest receptor within 2700 feet of a project under this section unless otherwise listed in subsection (k)."

The commission has changed the rule in response to portions of this comment. The rule has been updated to not require an impacts review if a property line or receptor is not with a 1/4 mile (Level 1) or 1/2 mile (Level 2), depending on the air contaminant. These distances are equivalent to the distances used on the modeling tables to establish the hourly emission limits for the PBR levels as specified in subsections (g) and (h) of this section.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested to "Eliminate the requirement to determine allowable site-wide lb/hr emissions from planned MSS operations that occur less frequently than weekly. Allow for individual modeling to evaluate short-term impact. The word "all" should be removed from the rule language and replaced with "short-term". The short-term potential impacts may only occur monthly, annually or even less frequently. The use of hourly rates is more stringent than Federal and other state rules. Consideration should be given differently for attainment versus nonattainment when making this requirement. They proposed a rule change to "Short-term emissions estimates must be based on representative operations scenario and planned MSS activities.""

The commission has not changed the rule in response to this comment. All hours of operation which are authorized must ensure protection of public health and welfare.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Annual emission estimates based on worst-case operations will grossly overstate emissions and not allow for proper SIP analysis. Worst-case scenarios are short-term events. Emissions that take place during such events to calculate emission over an entire year is not appropriate."

The commission has not changed the rule in response to this comment. Consistent with all emission estimation guidelines for any authorization (PBR, standard permit, permit), annual emissions are determined by the maximum lb/hr multiplied by the frequency of that scenario in hours per year, plus any other steady-state emissions and their respective frequency. The current PBR Registration instructions include the following: "Annual emission rates (tpy), which should be reflective of the average operation throughout the year...A description of the hours of operation and how they relate to emission rates on a short-term (maximum lb/hr) and long-term (maximum tpy) basis. . .. Variations in emissions must be clearly identified and accounted for in the maximum hourly and annual emission rates, if the process is a non-continuous batch operation, or there are widely varying operating scenarios. Additional information should be supplied to describe the emission variations."

EPA stated that, "30 TAC §116.620(k)(1) and 30 TAC §106.352(k)(1) states that all emissions estimates must be based on representative worst-case operations and planned MSS activities. What does TCEQ consider to be worst-case operations? Will the source be required to estimate emissions based on potential to emit at maximum throughput and capacity?"

The commission has not changed the rule in response to this comment. The current PBR Registration instructions include the following: "The applicant must attach the maximum hourly and total annual emission rates of the new or changed facility and include the following: Maximum hourly emission rates (lb/hr) should be based on the maximum (design) production capacity of the facility. Dividing the average annual emissions (tpy) by the annual hours of operation in order to determine hourly emissions (lb/hr) is unacceptable." In addition, the commission has required that any facility emissions which are reduced through operational restrictions or controls must be certified in accordance with §106.6.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested clarification that "the original authorization is still enforced and should not require registration provided the proposed criteria is still met (protectiveness). What to do about sites that had previous MSS but do not pass the proposed criteria or able to model protectiveness? What modeling criteria should be in place for MSS emissions (very short duration and sporadic). Modeling for consistent lb/hr short-term impact does not seem appropriate for MSS emissions unless true dispersion characteristics are taken into account. Need to better understand the proposal, strategy recommendations, and impact."

The commission confirms that until the applicable effective date of the new PBR to planned MSS, any previously claimed planned MSS under the previous version of the PBR is authorized as long as compliance demonstration documentation is maintained. The commission also confirms that the new requirements of the PBR

do not require registration, only protectiveness and records, for planned MSS. The tables in subsection (m) created by the commission for demonstrating emissions are protective are based on specific dispersion characteristics, typical of releases from blowdowns, pipeline purging, and fugitive venting - all typical of planned MSS releases. If modeling is used to demonstrate compliance with ESLs or ambient air standards, specific dispersion characteristics of release points are expected to be used to show hourly emissions are acceptable.

EPA requested clarification on whether "the source required to provide TCEQ with a copy of the modeling results to support the emissions evaluation."

The commission will require a copy of the modeling results used to support a registration.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Requiring that the smallest distance from any fugitive component will make this PBR unusable because there are fugitive components on pipes and safety release valves that are located away from the equipment for safety reasons that would have to be considered and that would put you closer to a receptor. Remove "fugitive component." A vent is an emissions point. They proposed to change the rule to read "((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, or vent, (excluding fugitive components, metering stations, or instrumentation) 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 Web page. (B) For each facility or group of facilities, the shortest corresponding distance from any emission point, or vent, (excluding fugitive components, metering stations, or instrumentation) 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."

The commission has not changed the rule in response to this comment. The new PBR allows for safety valves within 25 feet of an off-property receptor. The protectiveness review under subsection (k) allows for accurately representative location and quantity of emissions from any given release point for oil and gas facilities, including fugitives. The expected quantity of emissions from a set of safety valves is very small when compared to all other releases from a group of facilities, but their contribution must be considered as a part of a protectiveness evaluation to ensure a complete and reasonably accurate demonstration is performed.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "The way this is worded all emissions from fugitive or some other facility group would be treated as though they were being emitted from a single fugitive component. Requiring that the smallest distance from any fugitive component will make this PBR unusable because there are fugitive components on pipes and safety release valves that are located away from the equipment for safety reasons that would have to be considered and that would put you closer to a receptor."

The commission has not changed the rule in response to this comment. It is important to clarify that the demonstration method commented upon is a very conservative, simple method and would only be expected to be used for facilities located on very large tracts of property. At least three other demonstration methods are specifically included in the proposed PBR, all of which consider relative distance to receptors and quantity of emission relative to those points.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated that the "TCEQ should work to provide more realistic modeling results by allowing the use of geographically specific meteorological data and actual stack parameters. This is a simple change and can be done within a base modeling file defined by the TCEQ. Additional consideration should be to review the base modeling file with industry to determine an appropriate selection of parameters."

The commission must develop authorizations that are protective at any distance for facility emissions that can be located anywhere in the state. Since the approach is meant to be general in nature, there are inherent conservative assumptions made to account for all cases. The commission conducted refined modeling using a screening approach to define the receptor grid, meteorology, and emissions location. By representing all sources at the same location for modeling purposes, variations in facility configurations were not considered a major factor. However, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "The definition of receptor in subsection (b)(2) to include the property line for NAAQS demonstrations and nearest receptor for effects evaluation. The proposed subsection (k)(2)(A) states the shortest distance from any emission source to the nearest receptor (as defined in subsection (b)(2)) be utilized to demonstrate protectiveness with the Effect Screening Levels. However, the Table 1 Emission Impact Table Limits and Descriptions states that the most stringent of any applicable generic Table value "G" be determined from the shortest distance from any emission point to the nearest property line. We propose the Table 1 instructions be clarified to include the distance to the closest receptor (as defined in subsection (b)(2)) for effect screening levels demonstrations."

The commission agrees with this comment and has updated subsection (k)(1)(A) and (B) to clarify distance measurements to receptors or property lines are relevant only to ESLs and ambient air standards, respectively.

EDF commented that, "Unless the TCEQ can demonstrate that the acute exposures underlying the ATSDR's MRL of 9 ppb for benzene would otherwise be prevented by the TCEQ's one-hour benzene ESL, then the OGS PBR and Standard Permit should require the more protective emissions limits for benzene emissions that would result from use of the ATSDR MRL. In practice, this could be accomplished by adding a set of tables for 24-hour unitized concentrations (as a supplement to Tables 2-6) and modify Table 1 to require applicants to use the ATSDR 9 ppb acute MRL for benzene (in lieu of the one-hour ESL). A more general formulation to recognize the possibility that the ESL or MRL values may change over time, would be to require applicants to conduct a protectiveness review using both values, and then be subject to the more stringent of the two resulting emissions limits."

As indicated in the response to Representative Lon Burnam's comment above, both the TCEQ one-hour ReV and ATSDR 1 to 14-day MRL for benzene were derived based on a LOAEL for blood effects in mice identified from the same study (Rozen et al. 1984). However, the 1 to 14-day MRL of 9 ppb (28 µg/m3) based on blood effects in mice exposed for 6 days is unnecessarily conservative as the long-term non-carcinogenic ReV based on blood effects in publics exposed for years is 86 ppb (280 µg/m3) (TCEQ 2007). Long-term concentrations will meet the long-term carcinogenic-based ESL of 1.4 ppb (4.5 µg/m3), which is well below that based on non-carcinogenic blood effects in publics. Moreover, the one-hour ESL of 54 ppb (170 µg/m3) is below the long-term ReV based on non-carcinogenic blood effects in publics (86 ppb or 280 µg/m3). Thus, the one-hour ESL is protective of long-term noncarcinogenic blood effects and it is not necessary to set 24-hour emission limits based on the ATSDR 1 to 14-day MRL. Additionally, using hourly emission limits is consistent with the current enforcement policy.
Reference: TCEQ. 2007. Development Support Document for Benzene. Available from: ***http://tceq.com/assets/public/implementation/tox/dsd/final/benzene_71-43-2_final_10-15-07.pdf.***

The EDF analysis indicates the commission's modeling undermines the protectiveness of the proposal."

The commission has carefully considered all comments and concerns regarding the evaluation of potential impacts from oil and gas facilities. Specific responses to model selection, meteorological inputs, simulation of engine emissions, and downwash issues are addressed individually in this document. The commission is confident that the protectiveness evaluation which has been performed is reasonably conservative and representative of anticipated impacts from the oil and gas industry.

EDF stated that "the rule requires that "a site-wide analysis including all on-property sources should be conducted" for determining compliance with ambient air standards or ESLs. It is not clear what is meant by "on- property source{s}."" This provision should be clarified so that there is no doubt that all emissions within the circumference of the protectiveness review – not just operationally related emissions – must be evaluated in order to assure protectiveness of health and compliance with applicable standards. The specific values in this subsection should be revised to reflect the result of any changes to the modeling that TCEQ undertakes in response to comments."

The commission confirms that subsection (k)(5)(A)(iii) and (B)(ii) requires any facility under common control on the same property with similar emissions be considered in the impacts evaluation. These facilities do not have to be operationally dependent and may be authorized by any type of permit, standard permit, or PBR. The commission cannot agree that in all cases such a

comprehensive review is warranted. The commission has changed the rule consistent with the minor NSR permitting process impacts review and added options for very small emission changes to be exempt from this review, or require only a limited review.

EPA requested clarification to determine if the" TCEQ given any thought of how or when it will address future NAAQS requirements such as the one-hour requirement for SO_2."

The commission proposed and is adopting requirements for the newly promulgated hourly SO_2 NAAQS. Any future adoptions of state or federal AAQS must also be met by any authorized site, as emphasized by subsection (a)(3).

EPA commented that, "The modeling in support of the PBR and standard permit should also address the one-hour SO_2 standard that was finalized August 23, 2010. Small sweetening treaters are one of the several sources that could emit SO_2 levels that could generate impact levels that could be near the standard."

The commission has included requirements for the newly promulgated hourly SO_2 NAAQS and if a site has a sweetening treatment system, any resulting SO_2 emission releases must meet the specific demonstration requirements of subsection (k).

EPA commented with regard to "The tables attached to the standard permit and PBR list

$PM_{10}/_{2.5}$. It is unclear if the draft permit assumes use of PM_{10} as a surrogate for $PM_{2.5}$. We refer TCEQ to the recent Louisville Gas and Electric Petition Response, No. IV-2008-3, from the EPA Administrator Jackson, dated August 12, 2009. How does TCEQ plan to address $PM_{2.5}$ emissions in the draft permits?"

The commission has not changed the rule in response to this comment. The PM_{10} and $PM_{2.5}$ emission limits for both Level 1 and Level 2 of the PBR are identical, but based on the most restrictive of the $PM_{2.5}$. It is important to note that the quantification methods of these contaminant categories may be different. As more information on accurate quantification of $PM_{2.5}$ emissions are peer reviewed and become commonly available, the commission expects to update guidance on $PM_{2.5}$ emissions. Until that time, all PM_{10} quantified is very conservatively assumed to be $PM_{2.5}$.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated that, "Allowing several different methods is an appreciated change. We have minor comments on the implementation of SCREEN3 and ISC3."

The commission appreciates the support and is dedicated to discussing all implementation tools with stakeholders before Protocols or Guidance are finalized.

EDF stated that, "The TCEQ should remove the proposed options for applicants to submit their own screening or dispersion modeling. Such modeling would not be subject to public review and create an unnecessary strain on agency resources. If TCEQ decides to allow such modeling demonstrations, then the rules must explicitly include the instructions that applicants must follow (after appropriate administrative rulemaking procedures -- otherwise the public would not be allowed the opportunity to review and comment). In addition, if TCEQ allows applicant modeling, then it must be prepared to ensure the modeling section will review all dispersion modeling submitted for an OGS PBR or standard permit, and increase application fees accordingly."

The commission has not changed the rule in response to this comment. Modeling will be accepted under the new PBR, and not every registration will be reviewed. Instead, random audits of modeling demonstrations will be performed to ensure quality data and results. In all cases, applicants must follow very specific protocols for using modeling as a demonstration technique and the rule also requires these submittals to be part of a certified registration.

BP recommended that the "modeling be based on AERMOD as opposed to ISCST. ISC is no longer recognized by the EPA and there is political risk with the use of an EPA Non-Guideline model. It is acknowledged that AERMOD is more difficult to use than ISC but the extra effort is needed to avoid EPA criticism of this process. It is also recommended that the actual EPA version of AERMOD be used as opposed to a third party version (which EPA does not consider to be a Guideline version)."

AERMOD is EPA's preferred model for major NSR projects; that is, those new or modified major projects that trigger federal review. Since the Oil and Gas projects authorized under PBR or standard permit cannot trigger federal applicability, the commission used the ISCST3 model (ISC) to conduct the protectiveness review. The commission uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site.

AERMOD was developed to address complex atmospheric processes in a more refined way but the basis of the model and associated pre-processors and meteorology are not easily understood. Unlike ISC which has been vetted and improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them.

In addition, AERMOD is unnecessarily complex for general use. Since the protectiveness review for the PBR/standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air

soundings and values for surface characteristics such as roughness length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but must be estimated.

The values for these characteristics vary with location and time of year. To account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most representative coefficient.

BP commented that, "Modeling results should present meteorological data for the highest predicted impacts. This will ensure that all of the meteorological data are physically reasonable (e.g. low level mixing height)."

The commission developed reasonable and not absolute "worst-case" operational and meteorological scenarios.

The commission did not use a screening meteorology dataset based on the wind speed and stability categories used in the SCREEN model it includes some combinations of stability class and wind speed that are not considered standard stability class/wind speed combinations, such as stability class E with winds less than 2 meters/second (m/s), and F with winds greater than 3 m/s. The combinations of E and winds of 1 - 1.5 m/s are often excluded because the

algorithm developed by Turner to determine stability class from routine National Weather Service (NWS) observations excludes cases of E stability for wind speeds less than 4 knots (2 m/s). There might appear in a data set of on-site meteorological data with another stability class method but use of these data sets is not expected for this PBR or related standard permit.

The protectiveness review used meteorological data obtained from a single area. The data were quality assured following EPA guidance to fill in missing data; adjust low mixing heights; and adjust wind speeds to account for reported calms and differences in values due to various raw meteorological data sources (SAMSON and HUSWO).

Because only a single set was used, the commission used five5 years of data and adjusted the hourly wind directions to coincide with each 10 degree interval on a 360 degree polar grid (starting at 10 degrees and ending at 360 degree); that is, the EPA randomness factor was removed. Theoretically, this adjustment should provide impacts at a receptor that reflect worst-case meteorological conditions, since the plume centerline intersects the receptor directly.

BP recommended that, "The closest receptor distance be 100 meters. At receptor distances closer than this value, models are very sensitive to actual source geometry that is not reflected in these analyses."

The commission agrees that models are sensitive to actual source geometry.

However, the commission must develop authorizations that are protective at any distance for facility emissions that can be located anywhere in the state. Since the approach is meant to be general in nature, there are inherent conservative assumptions made to account for all cases. The commission used a screening approach to define the receptor grid, meteorology, and emissions location. By representing all sources at the same location for modeling purposes, variations in facility configurations were not considered a major factor. However, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

BP commented that, "Background concentrations should be based on the same statistical form as the standards. In addition, for oil and gas facilities, appropriate rural monitoring data should be used to evaluate background."

Background concentrations are not required and were not developed for this project. The protectiveness review considered the impact from only the sources seeking authorization through the PBR or related standard permit. Reasonable worst-case scenarios, emission caps, distance limitations, and inherent model assumptions combined with the use of maximum concentrations mitigate the need for background concentrations.

BP commented regarding fugitives based on "(a) 1-meter fugitive source (area source); (b) 3-meter point source representing loading; and (c) 6-meter point source representing tank hatches. The TCEQ modeling approach for fugitives is not the most appropriate methodology and recommended that process fugitives be modeled as a point source that includes building downwash (results in increased dilution of the plume near the source). The dimensions of the building can be based on the dimensions of the process unit, tank or truck loading. Alternatively, fugitives can be modeled as a volume source based on the dimensions of the structures. Model sensitivity testing should be performed to evaluate these modeling approaches. The modeling of fugitives (as a result of no plume rise) can be easily scaled as has been done in the proposed modeling."

Fugitive emissions were represented as three sources: a circular area source with a one-meter release height and nine-meter diameter; a point source with a three-meter release height; and a point source with a six-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 commission selected a circular area source type 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 commission represented the loading and tank fugitive emissions using the point source characterization and pseudo-point source parameters. The commission recognizes that there may be other appropriate source representations. The commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

BP commented that for modeling of Engines "where the TCEQ based engine modeling on greater than 1000 hp and less than 1000 hp, such a limited size distribution is not representative of engines in actual usage. It is recommended that a matrix of combustion unit capacity be developed (in conjunction with industry) so that permits can incorporate an engine capacity that corresponds to what is in use at a facility. In addition, based on the modeling results, it is not possible to relate the model parameters to an actual combustion unit; because thermal plume rise is a function of stack temperature and volume flow (heat content) and predicted concentrations are non-linear as a function of plume rise, modeling results cannot be scaled to other combustion units having different capacities. BP recommended that the modeling of these sources include generic building dimensions so that the modeling includes the effects of aerodynamic downwash. Downwash has the potential for affecting concentration near the source."

The dispersion modeling conducted for the protectiveness review was based on the information the commission had available at the time the analysis was performed. Additional information regarding various sizes of engines has been received since this analysis was performed. This information was used to modify the engine table. In addition, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

BP commented that flare modeling was "based on a review of the modeling runs, it is not possible to identify the volume of the gas being flared as well as the radiant heat loss. These parameters are critical in the determination of thermal plume rise. More information is needed to completely evaluate the modeling. Because thermal plume rise is a function of stack temperature and volume flow (heat content) and predicted concentrations are non-linear as a function of plume rise, modeling results cannot be scaled to other flaring rates. BP recommended that a matrix of flaring results be developed (in conjunction with industry) so that permits can incorporate a flaring rate that corresponds to the facility."

For dispersion modeling purposes, a flare is represented as a point source. A point source has the following required model input parameters: height, exit temperature, exit velocity, and exit diameter. For modeling flares, the exit temperature and exit velocity are default values. The exit diameter representation for flares was based on minimal regulatory requirements for flares, specifically requirements in 40 CFR §60.18. All flares are required to meet the heat capacity limits in the standard which are given in units of heat capacity per volume. Limited information available to the commission for flow rates of flares at oil and gas production sites were given in units of volume per time. Combining the minimal heat capacity standard with the limited flow rate data, a heat capacity per unit time was derived. The heat capacity per unit time value was used to calculate a minimal effective diameter for flares in the protectiveness review. In addition, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

EDF commented that since "The TCEQ used the ISCST3 model, and claimed that the predicted ground-level concentrations were conservative especially for short distances and low-level emissions. By running the AERMOD model instead of the ISCST3, we find that AERMOD predicts higher downwind concentrations – for all at least one source type configuration in each of TCEQ's proposed tables except flares. This was particularly true for low-level fugitives at longer distances, and other sources at shorter distances. To ensure that values in the tables result in protective emissions limits, the TCEQ should run both ISCST3 and AERMOD and choose the highest prediction for each source type configuration-distance combination."

AERMOD is EPA's preferred model for major NSR projects; that is, those new or modified major projects that trigger federal review. Since the Oil and Gas projects authorized under PBR or standard permit cannot be major, the commission used the ISC to conduct the protectiveness review. The commission uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site.

AERMOD was developed to address complex atmospheric processes in a more refined way but the basis of the model and associated pre-processors and meteorology are not easily understood. Unlike ISC which has been vetted and

improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them.

In addition, AERMOD is unnecessarily complex for general use. Since the protectiveness review for the PBR/standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air soundings and values for surface characteristics such as roughness length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but must be estimated.

The values for these characteristics vary with location and time of year. To account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most representative coefficient.

Representative Burnam "acknowledged the work TCEQ did in compiling tables with emission limits and is concerned that providing operators with two addition modeling options will create a loophole in the rule and perhaps circumvent standards that have been through public review. He is also concerned that TCEQ will not have the resources to adequately review alternative modeling results and would like to see these modeling options removed from the rule."

The commission has not changed the rule in response to this comment, and wants to clarify that the modeling options included do not create a "loop-hole", but instead are more representative, detailed, complex tools often used to demonstrate protectiveness. The commission is expecting to perform random audits of modeling demonstrations to ensure quality data and results. In all cases, applicants must follow very specific protocols for using modeling as a demonstration technique and the rule also requires these submittals to be part of a certified registration.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented on "§106.352(k) of the proposed rule requires that a demonstration of protectiveness be conducted using one of the methods listed in §106.352(k)(4). The purpose is to demonstrate that the predicted impacts associated with site's emissions do not exceed established NAAQS or TCEQ guideline levels (for VOCs). Since the proposed rule requires this demonstration of protectiveness, it follows that the purpose of the "cap" limits included in §106.352(g)(2), §106.352(g)(3) and §106.352(h)(2) are not necessary to demonstrate protectiveness. We request that the hourly emission limits be restricted to what can be demonstrated as protective using the modeling protocols provided at any distance. As such, more applicants would have the opportunity to attempt and demonstrate protectiveness using the required §106.352(k) methods."

The commission has not changed the rule in response to this comment. There are

important and distinct reasons to establish hourly limits on air contaminants, as well as require more stringent demonstrations or limits for sites with property lines or receptors in closer proximity that the distances used to create the emission limits.

EPA stated that, "ISC has not been EPA's guideline model for near field impacts since 2005/2006. EPA replaced ISC with AERMOD as the guideline model in December 2005 with a 1 year transition period. EPA is concerned that some eases may exist where AERMOD would predict higher impacts based on previous modeling comparisons that we have reviewed for these specific types of sources. EPA is concerned that the proposed PBR and standard permit will allow for some sources to construct and use modeling submitted by another facility at a later date using AERMOD (for PSD, or other permitting) that may show that a source was allowed to construct using the PBR or standard permit that actually shows an impact that will have to be reduced. The tightness of the new NO_2 and SO_2 one-hour standards especially raise a higher level of concern with ambient impacts of these types of facilities than previous standards. To further complicate matters and raise concerns is the issues of downwash and that these facilities sometimes have downwash cavity zones that extend off property. We recommend that to ensure that values in the tables result in protective emissions limits, the TCEQ should run both ISCST3 and AERMOD and choose the highest prediction for each source type configuration-distance combination."

AERMOD is EPA's preferred model for major NSR projects; that is, those new or modified major projects that trigger federal review. Since the Oil and Gas projects

authorized under PBR or standard permit cannot be major, the commission used the ISC to conduct the protectiveness review. The commission uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site.

AERMOD was developed to address complex atmospheric processes in a more refined way but the basis of the model and associated pre-processors and meteorology are not easily understood. Unlike ISC which has been vetted and improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them.

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The values for these characteristics vary with location and time of year. To account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most representative coefficient.

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Since the protectiveness review for the PBR/standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air soundings and values for surface characteristics such as roughness

length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but must be estimated.

Representative Burnam would like to see a different standard for benzene used in determining protectiveness. The TCEQ tables and setback distances are based on the agency's ESL for benzene of 54 parts per billion. He cites the ATSDR minimum risk level of 9 parts per billion as a standard that ma y be more appropriate for short-term exposure.

The commission has not changed the rule in response to this comment. The exposure duration for TCEQ short-term ESL of 54 ppb (170 µg/m3) is one hour. The one-hour ESL is a policy-based value for air permitting and represents 30 percent of the health-based one-hour reference value (ReV) of 180 ppb (580 µg/m3). However, the exposure duration for the ATSDR acute-duration inhalation minimal risk level (MRL) of 9 ppb (28 µg/m3) is 24 hours per day for up to 14 days. Both the TCEQ one-hour ReV and ATSDR 1 to 14-day MRL were derived from the same lowest-observed-adverse-effect level (LOAEL) value of 10.2 ppm identified from the six hours per day, 6-day inhalation study by Rozen et al. (1984). However, because ATSDR derives acute MRLs for 1 to 14 days, ATSDR adjusted the six-hour LOAEL to a longer exposure duration. On the other hand, TCEQ derives one-hour acute comparison values, so TCEQ adjusted the six-hour LOAEL to a one-hour exposure for the TCEQ one-hour ReV. Thus, the TCEQ one-hour benzene ReV was derived to be health protective for a one-hour exposure; while the ATSDR acute MRL is derived to be protective for 1 to 14-day exposure. Again, the one-hour

ESL for air permitting is based on 30 percent of the one-hour health-based ReV. Since the short-term modeling impacts for benzene are based on its hourly emission limit, it is more appropriate to use the one-hour ESL of 54 ppb for the protectiveness review.

Senator Davis "Supports the development of energy resources that is considerate of the air we breathe, water we drink, and health of families. Specifically I am pleased that as a result of our ongoing discussions that Texas is undertaking a number of important measures, including changing the industry's permit by rule and standard permit requirements for the first time in over 20 years."

Representative Burnam supports TCEQ for going through this rule making. He believes the rule being revised is long overdue and appreciates the scope, state-wide applicability, and protectiveness review requirement. He believes this rule is an important step in developing the state's abundant natural gas resources without endangering the health and safety of Texans in those areas where the resources are found. The rule should be protective of public health. Representative Burnam supports the requirement to do an effects evaluation to protect public health and the flexibility of the proposal to allow emission limits to vary with distance to the nearest receptor."

The commission appreciates the support in adopting a rule which ensures protectiveness.

EPA commented that the "TCEQ has proposed to define distance for sources that could contribute emissions that affect a receptor, which would include all adjacent sources of emissions under common control within a distance of 1/4 mile, EPA is extremely concerned about the cumulative impact that could occur with a number of sources that might use the PBR or standard permit. If a review was done of sources that have been recently installed in the Barnett Shale area in the last 5 years it is likely that a large number of the sources would have been able to be permitted under these proposed PBR or standard permit. TCEQ should conduct a cumulative assessment of a number of facilities being located within the minimum distance allowed to ensure that the cumulative impact would not be a concern for ambient standards, including the new one-hour NO_2 and SO_2 standards. EPA would recommend a grid pattern spacing based on the minimum distance either based on actual spacing in some of the most densely packed areas of the Barnett Shale or the 1/4 mile distance separation. Whatever distance is the more conservative ....have a concern that the cumulative impact of a number of sources permitted by PBR or standard permit could show problems with ambient standards if they were included in a cumulative modeling assessment. It is unclear if different owners could file PBRs or standard permits and be less than a 1/4 mile from each other, but not have to be concerned about cumulative impacts. We believe that without this cumulative level assessment, the PBR and standard permit could easily generate situations where cumulative modeling would show problems and potentially NAAQS exceedances."

The commission points out that the maximum modeled concentration typically occurs in a relatively limited area, as compared to the entire modeling domain. In particular, for the short-term averaging periods, such as the one-hour averaging period, modeled concentrations across the modeled area generally show that

ground level impacts are reduced significantly from the peak value as the pollutant travels a relatively short distance from the source, so that the peak modeled concentrations represent the source's impact at only a relatively few receptors within the modeled area. In addition, it is important to note that the temporal and spatial conditions which lead to a maximum impact by one source are seldom the same for other sources, such that maximum impacts of individual sources do not typically occur at the same location or at the same time.

Senator Davis stated that she "wants to thank you for joining me (Senator Davis) in developing balanced solutions that do not harm responsible drilling, while at the same time helping us to ensure the health and safety of families living in the Barnett Shale arena. Specifically I am pleased that as a result of our ongoing discussions that Texas is undertaking a number of important measures, including changing the industry's permit by rule and standard permit requirements for the first time in over 20 years."

The commission points out that the maximum modeled concentration typically occurs in a relatively limited area, as compared to the entire modeling domain. In particular, for the short-term averaging periods, such as the one-hour averaging period, modeled concentrations across the modeled area generally show that ground level impacts are reduced significantly from the peak value as the pollutant travels a relatively short distance from the source, so that the peak modeled concentrations represent the source's impact at only a relatively few receptors within the modeled area. In addition, it is important to note that the temporal and

spatial conditions which lead to a maximum impact by one source are seldom the same for other sources, such that maximum impacts of individual sources do not typically occur at the same location or at the same time. For example, in the illustration provided by EDF, the meteorological conditions contributing to the maximum predicted concentration.

In the background and summary of the factual basis for the proposed rules, TCEQ states that "{"existing} related facilities should be included in the new or revised PBR registration, but are not required to meet all the 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 requirement; however, the commission is proposing they should be included in the protectiveness evaluation and apply planned MSS requirements." 30 TAC §106.352(i) applies to any facilities using the section or previous versions of this section to comply with certain requirements which will, in fact, require these facilities to physically or operationally upgrade. For example, adopted §106.352(i)(4)(C) will require 98 percent control efficiency for VOC and H_2S emissions during compressor startup, regardless of the level of these emissions. This will require installation of controls. Per TCEQ's September 25, 2006 guidance, Planned Maintenance, Startup and Shutdown Emissions are authorized by the current version of §106.352, provided that the nearest receptor is at least 1200 feet away. Also, the previous version of §106.352 did not require registration unless a facility handles sour gas."

The commission has not changed the rule and respectfully disagrees with the comment. Specifically, subsection (i)(4) is an optional operating scenario which

has been specifically evaluated by the commission. This paragraph is only presented as an option, and the rule language is clear it is not a requirement and therefore no upgrades would be automatically required in the circumstance discussed in the comment.

EDF commented that the "final regulation should clarify that the evaluation be performed "for each OGS authorized under this section" instead of "{a}t and OGS." This language would ensure that the protectiveness review considers all relevant emissions within the circumference of the protectiveness review. At a minimum these should include emissions from all facilities under common ownership and account for background levels due to emissions from other sources. We do not support the provision that the analysis need only evaluate planned MSS if a claim under this section is only for planned MSS. The TCEQ should require that the demonstration of compliance (within the circumference of the protectiveness review) be made for MSS emissions aggregated with routine emissions from the site, plus emissions from any operationally related facilities, and background ambient levels from other sources. Otherwise, the authorized MSS emissions may not be protective of public health and welfare."

The commission has not changed the rule in response to this comment. The reasonably conservative impacts analysis performed by the commission establishes limits which are very protective. When releases occur from planned MSS, such as blowdowns or tank degassing, the short-term quantity will most likely be the most culpable source during that time, and therefore other operational releases will be dampened out by the higher, faster, releases.

EDF commented that the "TCEQ should expand the radius for aggregation of emissions for the protectiveness review beyond the proposed 1/4 mile distance. This radius should be sufficiently large so that the contribution of an upwind source becomes *de minimis* to a particular receptor when considered in combination with emissions from a downwind OGS."

The commission has not changed the rule in response to this comment. The commission has determined it is important that a distance cut-off is appropriate to capture the sources which are the most likely to contribute to a specific project under review.

TXOGA included "Examples of how the Proposed PBR and the Proposed Standard Permit are overly prescriptive and onerous compared to other PBRs and standard permits adopted by the TCEQ are numerous, but are highlighted by Proposed §106.352(b)(6)(B) and Subsection (b)(6)(B) of the Proposed Standard Permit, which would require OGS to conduct a case-by-case health impacts evaluation. The case-by-case evaluation and demonstration of compliance with ambient air standards and effects screening levels ("ESLs") that would be required by those proposed Subsections would be legally inappropriate to include as a condition of the Proposed PBR or Proposed Standard Permit since to do so would not be in "in harmony with the general objectives of the Act involved. TCEQ's air monitoring and toxicological studies have demonstrated that the current PBR establishes requirements that, if followed, result in insignificant contributions of air contaminants to the atmosphere. The proposed additional case-by-case evaluation provides no additional environmental benefits, but greatly increases the complexity of the OGS PBR and standard permit, and is, therefore, arbitrary and unreasonable. Furthermore, the TCAA clearly indicates that the Legislature intended for TCEQ to establish different levels of review and complexity for PBRs, standard permits, and individual permits. To require a facility to undergo a case-by-case evaluation of health effects in order to qualify for a PBR and/or a standard permit would make the review processes for the different authorizations strikingly similar in many important respects (i.e., the process for PBRs, standard permits, and individual permits would be equalized with regard to the case-by-case review). Thus, adopting the Proposed Rules would in important respects "equalize" the different permitting mechanisms. Equalizing the permitting mechanisms would not be in harmony with the legislative intent that can be gleaned from the plain language of the statute - which is to distinguish PBRs, standard permits, and individual permits from each other. Thus, TXOGA urges TCEQ to remove the requirement in the Proposed PBR requiring a case-by-case health impacts evaluation in proposed §106.352(b)(6). For the same reasons, TXOGA urges TCEQ to also remove the case-by-case requirements for a health effects evaluation in Subsection (b)(6) of the Proposed Standard Permit."

The commission respectfully disagrees with the comment, but seriously considered eliminating the modeling options for protectiveness evaluations. The options considered included established definitive hourly limits under which all facilities must comply, but found that the values which would need to be established were unrealistically low and would result in a rule which would not be useful. Secondly, the commission considered relying solely on the developed Tables, but realized that due to the unique and varying nature of the oil and gas industry, the use of the Tables may be too conservative in some instances and

inappropriately limit emissions. Thus, the commission determined that modeling demonstrations are appropriate options to demonstrate compliance.

EDF stated that the "TCEQ should develop a more comprehensive system for ensuring that emissions from proposed OGS, when combined with emissions from sources already in operation near a proposed oil and gas site, do not cause or contribute to exceedances of NAAQS or ESLs. As an initial step towards such a system, the TCEQ should modify the equations in Table 1 to account for existing ambient concentrations of relevant pollutants in the vicinity of a proposed site. Specifically, the TCEQ should substitute P and ESL in the equations with a variable to represent the difference between a NAAQS (or ESL) and recent monitored levels of the relevant pollutant in the area. Where no such monitoring data is available, TCEQ could provide default values."

Background concentrations are not required and were not developed for this project. The protectiveness review considered the impact from only the sources seeking authorization through the PBR/standard permit. Reasonable worst-case scenarios, emission caps, distance limitations, and inherent model assumptions combined with the use of maximum concentrations mitigate the need for background concentrations. Furthermore, ESLs are chemical-specific air concentrations set to protect public health and welfare and include an adjustment factor to address cumulative and aggregate exposure.

The commission points out that the maximum modeled concentration typically

occurs in a relatively limited area, as compared to the entire modeling domain. In particular, for the short-term averaging periods, such as the one-hour averaging period, modeled concentrations across the modeled area generally show that ground level impacts are reduced significantly from the peak value as the pollutant travels a relatively short distance from the source, so that the peak modeled concentrations represent the source's impact at only a relatively few receptors within the modeled area. In addition, it is important to note that the temporal and spatial conditions which lead to a maximum impact by one source are seldom the same for other sources, such that maximum impacts of individual sources do not typically occur at the same location or at the same time.

EPA notes that "TCEQ used the ISCST3 model, and claimed that the predicted ground-level concentrations were conservative especially for short distances and low-level emissions. In the modeling community this is thought to be the case based on some model comparisons between AERMOD and 1SC but most of those comparisons were not for Oil and Gas facilities. Oil and Gas facilities are a unique combination of low level point and fugitive source/emission types with relative close property boundaries. TCEQ's modeling scenario matrix should be run with AERMOD to verify that the values obtained with ISC are conservative."

AERMOD is EPA's preferred model for major NSR projects; that is, those new or modified major projects that trigger federal review. Since the Oil and Gas projects authorized under PBR or standard permit cannot be major, the commission used the ISCST3 model (ISC) to conduct the protectiveness review. The commission

uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site. However, once an applicant has used AERMOD, the TCEQ requires the use of AERMOD for major and minor projects at the site to ensure consistency of review.

AERMOD was developed to address complex atmospheric processes in a more refined way but the basis of the model and associated pre-processors and meteorology are not easily understood. Unlike ISC which has been vetted and improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them.

In addition, AERMOD is unnecessarily complex for general use. Since the protectiveness review for the PBR/standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air soundings and values for surface characteristics such as roughness length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but

must be estimated.

The values for these characteristics vary with location and time of year. To account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most representative coefficient.

EPA expressed concerns with the "minimum exit velocities for engines and turbines stacks of 159 ft/sec and 315 ft/sec. In reviewing information for engines and turbines for the types of sources that would be covered by this PBR and standard permit, we have noted actual stack data with exit velocities more often in the 75 to 150 ft/sec, with only a small percentage of the engines having exit velocities greater than 315 ft/sec. The higher stack velocity will give more momentum to the plume and thus lower near field concentrations. We believe the modeling analysis supporting the PBR and standard permit should either be redone for minimum velocities of 60 - 75 ft/sec or a lower value that will capture the minimum stack velocity based on TCEQ's review of stack data. Since exit velocity is a critical parameter in the modeling, the PBR and standard permit should have the source verify that their stack velocity is greater than the minimum velocity in order to use the PBR or standard permit. We believe that the minimum thermal temperature should also be used otherwise they should be going through normal permitting and modeling review."

The dispersion modeling conducted for the protectiveness review was based on the information the commission had available at the time the analysis was performed. Additional information regarding various sizes of engines has been received since this analysis was performed. This information was used to modify the engine table. In addition, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

EDF commented that the "TCEQ should provide data to support its assumptions about the flow rate and stack velocities used in the dispersion modeling, and make appropriate adjustments if necessary to reflect real world conditions. The TCEQ should rerun the dispersion model for engines with the adjusted assumptions and revise the unit values in Tables 3 and 4. In addition, to ensure real world operating conditions match the assumptions used in the protectiveness review, the TCEQ should add a condition to the draft OGS standard permit and PBR rules that limits engine and turbine exhaust exit velocities to a minimum of 159 ft/sec for small engines and 315 ft/sec for large engines (these are the exit velocities used in the TCEQ's modeling; or alternative values if TCEQ reruns the dispersion model with new exit velocities based on our comment), and requires periodic sampling and demonstration of compliance that such a limit is being met."

The dispersion modeling conducted for the protectiveness review was based on the information the commission had available at the time the analysis was performed. Additional information regarding various sizes of engines has been received since

this analysis was performed. This information was used to modify the engine table. In addition, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

Exterran "supports TCEQ's current formaldehyde impacts analysis in the Oil and Gas Proposal. As TCEQ established in the preamble to the Oil and Gas Proposal, the low levels of formaldehyde emissions from engine registration data do not warrant an additional formaldehyde impacts review for smaller OGS authorized by a PBR or Standard Permit. The agency's proposed approach and registration data review is supported by OEM not to exceed, or upper limit estimates of uncontrolled formaldehyde emissions from SI RICE and actual formaldehyde testing from SI RICE. Both the OEM data and the recent test data confirms TCEQ's review of the registration data and associated impacts assumptions. Recommendation: Taken together, the OEM uncontrolled emission data, additional SI RICE formaldehyde testing, and stringent federal standards focused on formaldehyde emissions from SI RICE strongly support TCEQ's Oil and Gas Proposal that recognizes the low formaldehyde emissions from SI RICE. The final Oil and Gas rule should not impose additional modeling requirements or duplicating existing federal standards and costly testing requirements. These items are discussed in more detail below. The OEM uncontrolled emission data in Attachment D-1 supports TCEQ's conclusion that for engines less than 1,000 hp, formaldehyde emissions are less than .57 lb/hr and for engines greater than 1,000 hp formaldehyde emissions are less than 1.15 lb/hr. Therefore, as modeled by TCEQ, SI RICE will not exceed the ESL hourly impacts for even the most conservative scenarios. The upper limit, not to exceed OEM data demonstrates that even in the most conservative emission estimates prepared by engine manufactures formaldehyde emissions from SI RICE remain extremely low. In addition to the NO and NO2 monitoring data submitted on June 7, 2010, Exterran will be submitting formaldehyde test data for TCEQ's consideration under separate cover."

The commission has re-evaluated formaldehyde based on comments received and has revised the rule to not require a specific demonstration for acceptable impacts. The commission also concurs with the commenter that the quantification of formaldehyde emissions may rely on manufacturer's or vendor testing of typical units and that this information is sufficient to demonstrate compliance with the SI RICE 40 CFR 63 MACT.

Pioneer recommended that, "Air monitoring be included as an alternative method to modeling in order to demonstrate protectiveness for operators who choose to install monitors to gather accurate, real-time data."

The commission has not included this option. The complexity and case-specific information which would be required is not appropriate in a standardized authorization.

Conoco Phillips is "requesting the following changes as it relates to the Scope of Protectiveness." The basis of the look up tables should be reviewed and revised consistent with the comments made by TXOGA and TPA. b) Modeling should be required only if he project affected sources exceed the thresholds in (k)(3)(B). c) Modeling should be performed only for the project affected sources. d) If protectiveness analysis involving the project affected sources only is not deemed adequate, and additional protective analysis for existing sources is necessary, it should be done as part of a two step process. First step should be for the project affected increases. If the impact from the project affected sources exceeds a factor such as 50 percent of the ambient standards or ESL thresholds then a more expanded analysis involving other sources within 1/4 mile at the site should be conducted. e) No formal lb/hr limits should be assigned to facilities at the PBR. Only long-term TPY limits should be applicable."

The commission has changed portions of the rule in response to this and similar comments. The basis of the source Tables (2) - (5F) have been revised and confirmed to be appropriate and reasonably conservative. Impacts analysis is only required if project-specific pollutant increases are greater than values established as the lowest at which no adverse impact would be expected at the closest distance. Impacts analysis is only required for the project-specific pollutant increases if the resulting concentrations are less than 10 percent of ESLs or SIL guidance for AAQS. Only in circumstances where project increases are greater than a portion of ESL or AAQS are other contributing sources under the same control, at the same property, with similar emissions, and within 1/4 mile must be considered. The commission has determined for this standardized authorization it is appropriate to establish hourly emission limits. Details of all of these determinations is included in the SECTION BY SECTION DISCUSSION of this document as well as the STANDARD PERMIT FOR OIL AND GAS PRODUCTON FACILITIES BACKGROUND document.

Senator Davis recommended the "TCEQ should scientifically re-evaluate whether effects review of facilities within 1/4 mile is adequate to protect public health. A company should not be able to count facilities in the same area as two different sites. This would affect subsection (b)(5)(C) as well."

The commission emphasizes that unless emission increases are so small as to meet the lowest acceptable emission impact at 50 feet, all projects must complete a contaminant-by-contaminant impacts evaluation for any receptor within 1/4 mile for the smallest of the PBR authorizations. The commission did carefully evaluate the requirements for larger emission releases and determined that an impacts review needs to be performed for any receptor within 1/2 mile to ensure protectiveness.

EDF commented that, "The pollutants covered under this section should also include CO, PM_{10}, $PM_{2.5}$ and formaldehyde."EPA commented on "30 TAC §116.620(b)(6)(B) and §106.352(b)(6)(B) requires a demonstration of compliance with ambient air standards for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and hydrogen sulfide (H_2S). TCEQ needs to demonstrate for the public record why the OGS should not provide a demonstration of compliance with carbon monoxide (CO) or particulate matter (PM, $PM_{2.5}$ and PM_{10})."

The commission has not changed the rule in response to this comment. The resulting quantities of CO, PM_{10} and $PM_{2.5}$ which meet the NAAQS at the most

conservative distances and dispersion characteristics (less than 250 hp engine, 8-foot stack, 50-foot distance) are 412 lb CO/hr, 35 lb PM_{10}/hr, and 0.9 lb $PM_{2.5}$/hr. These quantities are substantially greater than emissions from larger engines (which have better dispersion characteristics), and therefore there is no need to complete an impacts evaluation for these pollutants. After a detailed review of submitted information and federal background documents for 40 CFR 63 NESHAP Subpart ZZZZ, the commission has determined that the requirements of this federal standard is sufficient to establish controls on formaldehyde on new and existing engines. This is further supported by recent monitoring and does not show any concerns with monitored values of formaldehyde from engines associated with oil and gas production sites. Therefore, formaldehyde is omitted from the impacts evaluation requirements and emission limits for this PBR.

The Sierra Club and two individuals stated that the "TCEQ should ensure that the new PBR and standard permit do not interfere with attainment of national ambient air quality standards (NAAQS). They also commented that The Proposed Permits Must Ensure that Oil and Gas Sites Do Not Circumvent Major Source Requirements or Interfere with Attainment of the NAAQs."

The commission agrees with this comment and has adopted the new PBR with clear expectations of compliance demonstration with the NO_2 and SO_2 NAAQS. The protectiveness analysis for CO, PM_{10} and $PM_{2.5}$ shows that if emission limits as included in the rule are met, no additional demonstration is needed.

ETC recommended changes to subsection (b), "If a project is within 2,700 feet of a receptor: (i) Regardless of the emission limits established in subsection (b)(5)(D), hourly and annual emissions shall be limited based on the most stringent of subsections (g), (h), or (k) of this section; (ii) Compliance with ambient air standards shall be demonstrated for any receptor 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; and (iii) Compliance with hourly and annual effects screening levels (ESL) for benzene, toluene, and xylene shall be demonstrated at the nearest receptor within 2700 feet of a project under this section unless otherwise listed in subsection (k)."

The commission has changed the rule in response to portions of this comment. The rule has been updated to not require an impacts review if a property line or receptor is not with a 1/4 mile (Level 1) or 1/2 mile (Level 2), depending on the air contaminant. These distances are equivalent to the distances used on the modeling tables to establish the hourly emission limits for the PBR levels as specified in subsections (g) and (h).

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested to "Eliminate the requirement to determine allowable site-wide lb/hr emissions from planned MSS operations that occur less frequently than weekly. Allow for individual modeling to evaluate short-term impact. The word "all" should be removed from the rule language and replaced with "short-term". The short-term potential impacts may only occur monthly, annually or even less frequently. The use of hourly rates is more stringent than Federal and other state rules.

Consideration should be given differently for attainment versus nonattainment when making this requirement. They proposed a rule change to "Short-term emissions estimates must be based on representative operations scenario and planned MSS activities.""

The commission has not changed the rule in response to this comment. All hours of operation which are authorized must ensure protection of public health and welfare.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Annual emission estimates based on worst-case operations will grossly overstate emissions and not allow for proper SIP analysis. Worst-case scenarios are short-term events. Emissions that take place during such events to calculate emission over an entire year is not appropriate."

The commission has not change the rule in response to this comment. Consistent with all emission estimation guidelines for any authorization (PBR, standard permit, permit), annual emissions are determined by the maximum lb/hr multiplied by the frequency of that scenario in hours per year, plus any other steady-state emissions and their respective frequency. The current PBR Registration instructions include the following: "Annual emission rates (tpy), which should be reflective of the average operation throughout the year...A description of the hours of operation and how they relate to emission rates on a short-term (maximum lb/hr) and long-term (maximum tpy) basis . . . Variations in emissions must be clearly identified and accounted for in the maximum hourly

and annual emission rates, if the process is a non-continuous batch operation, or there are widely varying operating scenarios. Additional information should be supplied to describe the emission variations."

EPA stated that, "30 TAC §116.620(k)(1) and 30 TAC §106.352(k)(I) states that all emissions estimates must be based on representative worst-case operations and planned MSS activities. What does TCEQ consider to be worst-case operations? Will the source be required to estimate emissions based on potential to emit at maximum throughput and capacity?"

The commission has not changed the rule in response to this comment. The current PBR Registration instructions include the following: "The applicant must attach the maximum hourly and total annual emission rates of the new or changed facility and include the following: Maximum hourly emission rates (lb/hr) should be based on the maximum (design) production capacity of the facility. Dividing the average annual emissions (tpy) by the annual hours of operation in order to determine hourly emissions (lb/hr) is unacceptable." In addition, the commission has required that any facility emissions which are reduced through operational restrictions or controls must be certified in accordance with §106.6.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested clarification that "the original authorization is still enforced and should not require registration provided the proposed criteria is still met (protectiveness). What to do about sites that had previous MSS but do not pass the proposed criteria or able to model protectiveness? What modeling criteria should be in place for MSS emissions (very short duration and sporadic). Modeling for consistent lb/hr short-term impact does not seem appropriate for MSS emissions unless true dispersion characteristics are taken into account. Need to better understand the proposal, strategy recommendations, and impact."

The commission confirms that until the applicable effective date of the new PBR to planned MSS, any previously claimed planned MSS under the previous version of the PBR is authorized as long as compliance demonstration documentation is maintained. The commission also confirms that the new requirements of the PBR do not require registration, only protectiveness and records, for planned MSS. The tables in subsection (m) were created by the commission for demonstrating emissions are protective and are based on specific dispersion characteristics, typical of releases from blowdowns, pipeline purging, and fugitive venting - all typical of planned MSS releases. If modeling is used to demonstrate compliance with ESLs or AAQS, specific dispersion characteristics of release points are expected to be used to show hourly emissions are acceptable.

EPA requested clarification on whether "the source is required to provide TCEQ with a copy of the modeling results to support the emissions evaluation."

The commission will require a copy of the modeling results used to support a registration.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Requiring that the smallest distance from any fugitive component will make this PBR unusable because there are fugitive components on pipes and safety release valves that are located away from the equipment for safety reasons that would have to be considered and that would put you closer to a receptor. Remove "fugitive component." A vent is an emissions point. They proposed to change the rule to read "(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, or vent, (excluding fugitive components, metering stations, or instrumentation) 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 Web page. (B) For each facility or group of facilities, the shortest corresponding distance from any emission point, or vent, (excluding fugitive components, metering stations, or instrumentation) 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."

The commission has not changed the rule in response to this comment. The new PBR allows for safety valves within 25 feet of an off-property receptor. The protectiveness review under subsection (k) allows for accurately representative location and quantity of emissions from any given release point for oil and gas facilities, including fugitives. The expected quantity of emissions from a set of safety valves is very small when compared to all other releases from a group of facilities, but their contribution must be considered as a part of a protectiveness evaluation to ensure a complete and reasonably accurate demonstration is

performed.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "The way this is worded all emissions from fugitive or some other facility group would be treated as though they were being emitted from a single fugitive component. Requiring that the smallest distance from any fugitive component will make this PBR unusable because there are fugitive components on pipes and safety release valves that are located away from the equipment for safety reasons that would have to be considered and that would put you closer to a receptor."

The commission has not changed the rule in response to this comment. It is important to clarify that the demonstration method commented upon is a very conservative, simple method and would only be expected to be used for facilities located on very large tracts of property. At least three other demonstration methods are specifically included in the proposed PBR, all of which consider relative distance to receptors and quantity of emission relative to those points.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated that the "TCEQ should work to provide more realistic modeling results by allowing the use of geographically specific meteorological data and actual stack parameters. This is a simple change and can be done within a base modeling file defined by the TCEQ. Additional consideration should be to review the base modeling file with industry to determine an appropriate selection of parameters."

The commission must develop authorizations that are protective at any distance for facility emissions that can be located anywhere in the state. Since the approach is meant to be general in nature, there are inherent conservative assumptions made to account for all cases. The commission used a screening approach to define the receptor grid, meteorology, and emissions location. By representing all sources at the same location for modeling purposes, variations in facility configurations were not considered a major factor. However, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "The definition of receptor in (b)(2) to include the property line for NAAQS demonstrations and nearest receptor for effects evaluation. The proposed (k)(2)(A) states the shortest distance from any emission source to the nearest receptor (as defined in (b)(2)) be utilized to demonstrate protectiveness with the Effect Screening Levels. However, the Table 1 Emission Impact Table Limits and Descriptions states that the most stringent of any applicable generic Table value "G" be determined from the shortest distance from any emission point to the nearest property line. We propose the Table 1 instructions be clarified to include the distance to the closest receptor (as defined in (b)(2)) for effect screening levels demonstrations."

The commission agrees with this comment and has updated subsection (k)(1)(A) - (B) to clarify distance measurements to receptors or property lines are relevant only to ESLs and AAQS, respectively.

Representative Burnam stated he strongly supports the Environmental Defense Fund (EDF) regarding deficiencies in dispersion modeling including model selection, meteorological inputs, simulation of engine emissions, and stack-tip downwash. He urges the commission to act on the EDF recommendations as modeling determines the hourly and annual emission limits, setbacks, and overall assurance of protectiveness. The EDF analysis indicates the commission's modeling undermines the protectiveness of the proposal.

The commission has carefully considered all comments and concerns regarding the evaluation of potential impacts from oil and gas facilities. Specific responses to model selection, meteorological inputs, simulation of engine emissions, and downwash issues are addressed individually in this document. The commission is confident that the protectiveness evaluation which has been performed is reasonably conservative and representative of anticipated impacts from the oil and gas industry.

EDF stated that "the rule requires that "a site-wide analysis including all on-property sources should be conducted" for determining compliance with ambient air standards or ESLs. It is not clear what is meant by "on- property source(s)." This provision should be clarified so that there is no doubt that all emissions within the circumference of the protectiveness review – not just operationally related emissions – must be evaluated in order to assure protectiveness of health and compliance with applicable standards. The specific values in this subsection should be revised to reflect the result of any changes to the modeling that TCEQ undertakes in response to comments."

The commission confirms that subsection (k)(5)(A)(iii) and (B)(ii) requires any facility under common control on the same property with similar emissions be considered in the impacts evaluation. These facilities do not have to be operationally dependent and may be authorized by any type of permit, standard permit, or PBR. The commission cannot agree that in all cases such a comprehensive review is warranted. The commission has changed the rule consistent with the minor NSR permitting process impacts review and added options for very small emission changes to be exempt from this review, or require only a limited review.

EPA requested clarification to determine if the" TCEQ given any thought of how or when it will address future NAAQS requirements such as the one-hour requirement for SO_2."

The commission proposed and is adopting requirements for the newly promulgated hourly SO_2 NAAQS. Any future adoptions of state or federal AAQS must also be met by any authorized site, as emphasized by subsection (a)(3).

EPA commented that, "The modeling in support of the PBR and standard permit should also address the one-hour SO_2 standard that was finalized August 23, 2010. Small sweetening treaters are one of the several sources that could emit S02 levels that could generate impact levels that could be near the standard."

The commission has included requirements for the newly promulgated hourly SO_2 NAAQS and if a site has a sweetening treatment system, any resulting SO_2 emission releases must meet the specific demonstration requirements of subsection (k).

EPA commented with regard to "The tables attached to the standard permit and PBR list $PM_{10}/_{2.5}$. It is unclear if the draft permit assumes use of PM_{10} as a surrogate for $PM_{2.5}$. We refer TCEQ to the recent Louisville Gas and Electric Petition Response, No. IV-2008-3, from the EPA Administrator Jackson, dated August 12, 2009. How does TCEQ plan to address $PM_{2.5}$ emissions in the draft permits?"

The commission has not changed the rule in response to this comment. The PM_{10} and $PM_{2.5}$ emission limits for both Level 1 and Level 2 of the PBR are identical, but based on the most restrictive of the $PM_{2.5}$ NAAQS. It is important to note that the quantification methods of these contaminant categories may be different. As more information on accurate quantification of $PM_{2.5}$ emissions are peer reviewed and become commonly available, the commission expects to update guidance on $PM_{2.5}$ emissions. Until that time, all PM_{10} quantified is very conservatively assumed to be $PM_{2.5}$.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated that, "Allowing several different methods is an appreciated change. We have minor comments on the implementation of SCREEN3 and ISC3."

The commission appreciates the support and is dedicated to discussing all implementation tools with stakeholders before Protocols or Guidance are finalized.

EDF stated that, "The TCEQ should remove the proposed options for applicants to submit their own screening or dispersion modeling. Such modeling would not be subject to public review and create an unnecessary strain on agency resources. If TCEQ decides to allow such modeling demonstrations, then the rules must explicitly include the instructions that applicants must follow (after appropriate administrative rulemaking procedures -- otherwise the public would not be allowed the opportunity to review and comment). In addition, if TCEQ allows applicant modeling, then it must be prepared to ensure the modeling section will review all dispersion modeling submitted for an OGS PBR or standard permit, and increase application fees accordingly."

The commission has not changed the rule in response to this comment. Modeling will be accepted under the new PBR, and not every registration will be reviewed. Instead, random audits of modeling demonstrations will be performed to ensure quality data and results. In all cases, applicants must follow very specific protocols for using modeling as a demonstration technique and the rule also requires these submittals to be part of a certified registration.

BP recommended that the "modeling be based on AERMOD as opposed to ISCST. ISC is no longer recognized by the EPA and there is political risk with the use of an EPA Non-Guideline model. It is acknowledged that AERMOD is more difficult to use than ISC but the extra effort is needed to avoid EPA criticism of this process. It is also recommended that the actual EPA version of AERMOD be used as opposed to a third party version (which EPA does not consider to be a Guideline version)."

AERMOD is EPA's preferred model for major NSR; that is, those new major sources or major modifications to existing major sources that trigger federal review. Since the Oil and Gas projects authorized under PBR or standard permit cannot trigger federal applicability, the commission used the ISC to conduct the protectiveness review. The commission uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site.

AERMOD was developed to address complex atmospheric processes in a more refined way but the basis of the model and associated pre-processors and meteorology are not easily understood.

Unlike ISC which has been vetted and improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them. In addition, AERMOD is unnecessarily complex for general use. Since the protectiveness review for the PBR/standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air soundings and values for surface characteristics such as roughness length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but must be estimated.

The values for these characteristics vary with location and time of year. To account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most representative coefficient.

BP commented that, "Modeling results should present meteorological data for the highest predicted impacts. This will ensure that all of the meteorological data are physically reasonable (e.g. low-level mixing height)."

The commission developed reasonable and not absolute "worst-case" operational and meteorological scenarios. The commission did not use a screening

meteorology dataset based on the wind speed and stability categories used in the SCREEN model it includes some combinations of stability class and wind speed that are not considered standard stability class/wind speed combinations, such as stability class E with winds less than 2 meters/second (m/s), and F with winds greater than 3 m/s. The combinations of E and winds of 1 - 1.5 m/s are often excluded because the algorithm developed by Turner to determine stability class from routine National Weather Service (NWS) observations excludes cases of E stability for wind speeds less than 4 knots (2 m/s). There might appear in a data set of on-site meteorological data with another stability class method but use of these data sets is not expected for this PBR or related standard permit.

The protectiveness review used meteorological data obtained from a single area. The data were quality assured following EPA guidance to fill in missing data; adjust low mixing heights; and adjust wind speeds to account for reported calms and differences in values due to various raw meteorological data sources (SAMSON and HUSWO).

Because only a single set was used, the commission used 5 years of data and adjusted the hourly wind directions to coincide with each 10 degree interval on a 360 degree polar grid (starting at 10 degrees and ending at 360 degree); that is, the EPA randomness factor was removed. Theoretically, this adjustment should provide impacts at a receptor that reflect worst-case meteorological conditions, since the plume centerline intersects the receptor directly.

BP recommended that, "The closest receptor distance be 100 meters. At receptor distances closer than this value, models are very sensitive to actual source geometry that is not reflected in these analyses."

The commission agrees that models are sensitive to actual source geometry. However, the commission must develop authorizations that are protective at any distance for facility emissions that can be located anywhere in the state. Since the approach is meant to be general in nature, there are inherent conservative assumptions made to account for all cases. The commission used a screening approach to define the receptor grid, meteorology, and emissions location. By representing all sources at the same location for modeling purposes, variations in facility configurations were not considered a major factor. However, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

BP commented that, "Background concentrations should be based on the same statistical form as the standards. In addition, for oil and gas facilities, appropriate rural monitoring data should be used to evaluate background."

Background concentrations are not required and were not developed for this project. The protectiveness review considered the impact from only the sources seeking authorization through the PBR or related standard permit. Reasonable worst-case scenarios, emission caps, distance limitations, and inherent model

assumptions combined with the use of maximum concentrations mitigate the need for background concentrations.

BP commented regarding fugitives based on "(a) 1-meter fugitive source (area source); (b) 3-meter point source representing loading; and (c) 6-meter point source representing tank hatches. The TCEQ modeling approach for fugitives is not the most appropriate methodology and recommended that process fugitives be modeled as a point source that includes building downwash (results in increased dilution of the plume near the source). The dimensions of the building can be based on the dimensions of the process unit, tank or truck loading. Alternatively, fugitives can be modeled as a volume source based on the dimensions of the structures. Model sensitivity testing should be performed to evaluate these modeling approaches. The modeling of fugitives (as a result of no plume rise) can be easily scaled as has been done in the proposed modeling."

Fugitive emissions were represented as three sources: a circular area source with a 1 meter release height and 9-meter 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 commission selected a circular area source type 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 commission

represented the loading and tank fugitive emissions using the point source characterization and pseudo-point source parameters. The commission recognizes that there may be other appropriate source representations. The commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

BP commented that for modeling of Engines "where the TCEQ based engine modeling on greater than 1000 hp and less than 1000 hp, such a limited size distribution is not representative of engines in actual usage. It is recommended that a matrix of combustion unit capacity be developed (in conjunction with industry) so that permits can incorporate an engine capacity that corresponds to what is in use at a facility. In addition, based on the modeling results, it is not possible to relate the model parameters to an actual combustion unit; because thermal plume rise is a function of stack temperature and volume flow (heat content) and predicted concentrations are non-linear as a function of plume rise, modeling results cannot be scaled to other combustion units having different capacities. BP recommended that the modeling of these sources include generic building dimensions so that the modeling includes the effects of aerodynamic downwash. Downwash has the potential for affecting concentration near the source."

The dispersion modeling conducted for the protectiveness review was based on the information the commission had available at the time the analysis was performed. Additional information regarding various sizes of engines has been received since this analysis was performed. This information was used to modify the engine

table. In addition, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

BP commented that flare modeling was "based on a review of the modeling runs, it is not possible to identify the volume of the gas being flared as well as the radiant heat loss. These parameters are critical in the determination of thermal plume rise. More information is needed to completely evaluate the modeling. Because thermal plume rise is a function of stack temperature and volume flow (heat content) and predicted concentrations are non-linear as a function of plume rise, modeling results cannot be scaled to other flaring rates. BP recommended that a matrix of flaring results be developed (in conjunction with industry) so that permits can incorporate a flaring rate that corresponds to the facility."

For dispersion modeling purposes, a flare is represented as a point source. A point source has the following required model input parameters: height, exit temperature, exit velocity, and exit diameter. For modeling flares, the exit temperature and exit velocity are default values. The exit diameter representation for flares was based on minimal regulatory requirements for flares, specifically requirements in 40 CFR §60.18. All flares are required to meet the heat capacity limits in the standard which are given in units of heat capacity per volume. Limited information available to the commission for flow rates of flares at oil and gas production sites were given in units of volume per time. Combining the minimal heat capacity standard with the limited flow rate data, a heat capacity per

unit time was derived. The heat capacity per unit time value was used to calculate a minimal effective diameter for flares in the protectiveness review. In addition, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

EDF commented that since "The TCEQ used the ISCST3 model, and claimed that the predicted ground-level concentrations were conservative especially for short distances and low-level emissions. By running the AERMOD model instead of the ISCST3, we find that AERMOD predicts higher downwind concentrations – for all at least one source type configuration in each of TCEQ's proposed tables except flares. This was particularly true for low-level fugitives at longer distances, and other sources at shorter distances. To ensure that values in the tables result in protective emissions limits, the TCEQ should run both ISCST3 and AERMOD and choose the highest prediction for each source type configuration-distance combination."

AERMOD is EPA's preferred model for major NSR; that is, those new major sources or major modifications to existing major sources that trigger federal review. Since the Oil and Gas projects authorized under PBR or standard permit cannot be major, the commission used the ISC to conduct the protectiveness review. The commission uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be

understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site.

AERMOD was developed to address complex atmospheric processes in a more refined way but the basis of the model and associated pre-processors and meteorology are not easily understood. Unlike ISC which has been vetted and improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them. In addition, AERMOD is unnecessarily complex for general use.

Since the protectiveness review for the PBR/standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air soundings and values for surface characteristics such as roughness length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but must be estimated.

The values for these characteristics vary with location and time of year. To account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most

representative coefficient.

Representative Burnam "acknowledged the work TCEQ did in compiling tables with emission limits and is concerned that providing operators with two addition modeling options will create a loophole in the rule and perhaps circumvent standards that have been through public review. He is also concerned that TCEQ will not have the resources to adequately review alternative modeling results and would like to see these modeling options removed from the rule."

The commission has not changed the rule in response to this comment, and wants to clarify that the modeling options included do not create a "loop-hole", but instead are more representative, detailed, complex tools often used to demonstrate protectiveness. The commission is expecting to perform random audits of modeling demonstrations to ensure quality data and results. In all cases, applicants must follow very specific protocols for using modeling as a demonstration technique and the rule also requires these submittals to be part of a certified registration.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented on "§106.352(k) of the proposed rule requires that a demonstration of protectiveness be conducted using one of the methods listed in §106.352(k)(4). The purpose is to demonstrate that the predicted impacts associated with site's emissions do not exceed established NAAQS or TCEQ guideline levels (for VOCs). Since the proposed rule requires this demonstration of protectiveness, it follows that the purpose of the "cap" limits included in §106.352(g)(2), §106.352(g)(3) and §106.352(h)(2) are not necessary to demonstrate protectiveness. We request that the hourly emission limits be restricted to what can be demonstrated as protective using the modeling protocols provided at any distance. As such, more applicants would have the opportunity to attempt and demonstrate protectiveness using the required §106.352(k) methods."

The commission has not changed the rule in response to this comment. There are important and distinct reasons to establish hourly limits on air contaminants, as well as require more stringent demonstrations or limits for sites with property lines or receptors in closer proximity that the distances used to create the emission limits.

EPA stated that, "ISC has not been EPA's guideline model for near field impacts since 2005/2006. EPA replaced ISC with AERMOD as the guideline model in December 2005 with a 1 year transition period. EPA is concerned that some eases may exist where AERMOD would predict higher impacts based on previous modeling comparisons that we have reviewed for these specific types of sources. EPA is concerned that the proposed PBR and standard permit will allow for some sources to construct and use modeling submitted by another facility at a later date using AERMOD (for PSD, or other permitting) that may show that a source was allowed to construct using the PBR or standard permit that actually shows an impact that will have to be reduced. The tightness of the new NO_2 and SO_2 one-hour standards especially raise a higher level of concern with ambient impacts of these types of facilities than previous standards. To further complicate matters and raise concerns is the issues of downwash and that these facilities sometimes have downwash cavity zones that extend off property. We recommend that to ensure that values in the tables result in protective emissions limits, the TCEQ should run both ISCST3 and AERMOD and choose the highest prediction for each source type configuration-distance combination."

AERMOD is EPA's preferred model for major NSR; that is, those new major sources or major modifications to existing major sources that trigger federal review. Since the Oil and Gas projects authorized under PBR or standard permit cannot be major, the commission used the ISC to conduct the protectiveness review. The commission uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site.

AERMOD was developed to address complex atmospheric processes in a more refined way but the basis of the model and associated pre-processors and meteorology are not easily understood. Unlike ISC which has been vetted and improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them.

In addition, AERMOD is unnecessarily complex for general use. Since the

protectiveness review for the PBR and standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air soundings and values for surface characteristics such as roughness length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but must be estimated.

The values for these characteristics vary with location and time of year. To account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most representative coefficient.

Representative Burnam "would like to see a different standard for benzene used in determining protectiveness. The TCEQ tables and setback distances are based on the agency's ESL for benzene of 54 parts per billion. He cites the ATSDR minimum risk level of 9 parts per billion as a standard that ma y be more appropriate for short-term exposure. Using the ATSDR standard results in an emission limit that is approximately one half for a given point source from a receptor."

The commission has not changed the rule in response to this comment. The

exposure duration for TCEQ short-term ESL of 54 ppb (170 µg/m3) is one hour. The one-hour ESL is a policy-based value for air permitting and represents 30 percent of the health-based one-hour reference value (ReV) of 180 ppb (580 µg/m3). However, the exposure duration for the ATSDR acute-duration inhalation minimal risk level (MRL) of 9 ppb (28 µg/m3) is 24 hours per day for up to 14 days. Both the TCEQ one-hour ReV and ATSDR 1 to 14-day MRL were derived from the same lowest-observed-adverse-effect level (LOAEL) value of 10.2 ppm identified from the six hours per day, 6-day inhalation study by Rozen et al. (1984). However, because ATSDR derives acute MRLs for 1 to 14 days, ATSDR adjusted the six-hour LOAEL to a longer exposure duration. On the other hand, TCEQ derives one-hour acute comparison values, so TCEQ adjusted the six-hour LOAEL to a one-hour exposure for the TCEQ one-hour ReV. Thus, the TCEQ one-hour benzene ReV was derived to be health protective for a one-hour exposure; while the ATSDR acute MRL is derived to be protective for 1 to 14-day exposure. Again, the one-hour ESL for air permitting is based on 30 percent of the one-hour health-based ReV. Since the short-term modeling impacts for benzene are based on its hourly emission limit, it is more appropriate to use the one-hour ESL of 54 ppb for the protectiveness review.

Senator Davis supports the development of energy resources that is considerate of the air we breathe, water we drink, and health of families. She commends TCEQ for undertaking this review of the oil and gas regulations but notes that it is the first such review in 20 years and several thousand pieces of oil and gas equipment are currently operating in the Barnett Shale region. If the rule review had been conducted at the outset of urban drilling, this equipment would be monitored and the public would be assured that its health was not an afterthought. She suggests several specific rule changes to strengthen protectiveness which will be noted in the applicable sections. She commends the TCEQ in developing balanced solutions that do not harm responsible drilling, while at the same time helping us to ensure the health and safety of families living in the Barnett Shale arena. Specifically she is pleased that as a result of our ongoing discussions that Texas is undertaking a number of important measures, including changing the industry's permit by rule and standard permit requirements for the first time in over 20 years.

The commission appreciates the support in adopting a rule which ensures protectiveness.

EPA commented that the "TCEQ has proposed to define distance for sources that could contribute emissions that affect a receptor, which would include all adjacent sources of emissions under common control within a distance of 1/4 mile, EPA is extremely concerned about the cumulative impact that could occur with a number of sources that might use the PBR or standard permit. If a review was done of sources that have been recently installed in the Barnett Shale area in the last 5 years it is likely that a large number of the sources would have been able to be permitted under these proposed PBR or standard permit. TCEQ should conduct a cumulative assessment of a number of facilities being located within the minimum distance allowed to ensure that the cumulative impact would not be a concern for ambient standards, including the new one-hour NO_2 and SO_2 standards. EPA would recommend a grid pattern spacing based on the minimum distance either based on actual spacing in some of the most densely packed areas of the Barnett Shale or the 1/4 mile distance separation. Whatever distance is the more conservative. As noted elsewhere, EPA has issued guidance that indicates that sources potentially should be aggregated even if they are separated by a distance of greater than 1/4 mile, and this is a case-by-case decision. Even if EPA agreed that sources separated by 1/4 mile do not have to be aggregated, we still have a concern that the cumulative impact of a number of sources permitted by PBR or standard permit could show problems with ambient standards if they were included in a cumulative modeling assessment. It is unclear if different owners could file PBRs or standard permits and be less than a 1/4 mile from each other, but not have to be concerned about cumulative impacts. We believe that without this cumulative level assessment, the PBR and standard permit could easily generate situations where cumulative modeling would show problems and potentially NAAQS exceedances."

The commission points out that the maximum modeled concentration typically occurs in a relatively limited area, as compared to the entire modeling domain. In particular, for the short-term averaging periods, such as the one-hour averaging period, modeled concentrations across the modeled area generally show that ground level impacts are reduced significantly from the peak value as the pollutant travels a relatively short distance from the source, so that the peak modeled concentrations represent the source's impact at only a relatively few receptors within the modeled area. In addition, it is important to note that the temporal and spatial conditions which lead to a maximum impact by one source are seldom the same for other sources, such that maximum impacts of individual sources do not typically occur at the same location or at the same time.

Senator Davis stated that she "wants to thank you for joining me (Senator Davis) in developing balanced solutions that do not harm responsible drilling, while at the same time helping us to ensure the health and safety of families living in the Barnett Shale arena. Specifically I am pleased that as a result of our ongoing discussions that Texas is undertaking a number of important measures, including changing the industry's permit by rule and standard permit requirements for the first time in over 20 years."

The commission points out that the maximum modeled concentration typically occurs in a relatively limited area, as compared to the entire modeling domain. In particular, for the short-term averaging periods, such as the one-hour averaging period, modeled concentrations across the modeled area generally show that ground level impacts are reduced significantly from the peak value as the pollutant travels a relatively short distance from the source, so that the peak modeled concentrations represent the source's impact at only a relatively few receptors within the modeled area. In addition, it is important to note that the temporal and spatial conditions which lead to a maximum impact by one source are seldom the same for other sources, such that maximum impacts of individual sources do not typically occur at the same location or at the same time. For example, in the illustration provided by EDF, the meteorological conditions contributing to the maximum predicted concentration from the 30ft vent at source A occurs during neutral conditions. The meteorological conditions contributing to the maximum predicted concentration from the 30ft vent at source B occurs during very unstable conditions. Neutral and very unstable conditions do not occur at the same time in the real world; therefore, it is not expected that the scenario described would ever

occur.

TPA commented that, "Modeling should not be required for replacements where the potential to emit does not increase or where the replacement does not result in a change in the character of emissions or an increase in the quantity of emissions. It would not make sense for a replacement that has no greater impact than its predecessor to undergo or to trigger an impacts review."

The commission agrees with the comment and notes that subsection (b)(8) and (k) state that impacts reviews are only required when there is an increase in emissions associated with a project.

El Paso commented that the "TCEQ's explanation of subsection (i)(4) is contradictory. 30-foot vent at source A occurs during neutral conditions. The meteorological conditions contributing to the maximum predicted concentration from the 30-foot vent at source B occurs during very unstable conditions. Neutral and very unstable conditions do not occur at the same time in the real world; therefore, it is not expected that the scenario described would ever occur.

TPA commented that, "Modeling should not be required for replacements where the potential to emit does not increase or where the replacement does not result in a change in the character of emissions or an increase in the quantity of emissions. It would not make sense for a replacement that has no greater impact than its predecessor to undergo or to trigger an impacts review."

On page 19 of the background and summary of the factual basis for the proposed rules, TCEQ states that "{"existing} related facilities should be included in the new or revised PBR registration, but are not required to meet all the 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 requirement; however, the commission is proposing they should be included in the protectiveness evaluation and apply planned MSS requirements." 30 TAC §106.352(i) applies to any facilities using the section or previous versions of this section to comply with certain requirements which will, in fact, require these facilities to physically or operationally upgrade. For example, proposed §106.352(1)(4)(C) will require 98 percent control efficiency for VO_X and H_2S emissions during compressor startup, regardless of the level of these emissions. This will require installation of controls. Per TCEQ's September 25, 2006 guidance, Planned Maintenance, Startup and Shutdown Emissions are authorized by the current version of §106.352, provided that the nearest receptor is at least 1,200 feet away. Also, the previous version of §106.352 did not require registration unless a facility handles sour gas."

The commission has not changed the rule and respectfully disagrees with the comment. Specifically, subsection (i)(4) is an optional operating scenario which has been specifically evaluated by the commission. Paragraph (4) is only presented as an option, and the rule language is clear it is not a requirement and therefore no upgrades would be automatically required in the circumstance discussed in the comment.

EDF commented that the "final regulation should clarify that the evaluation be performed "for each OGS authorized under this section" instead of "{"a}t and OGS." This language would ensure that the protectiveness review considers all relevant emissions within the circumference of the protectiveness review. At a minimum these should include emissions from all facilities under common ownership and account for background levels due to emissions from other sources. We do not support the provision that the analysis need only evaluate planned MSS if a claim under this section is only for planned MSS. The TCEQ should require that the demonstration of compliance (within the circumference of the protectiveness review) be made for MSS emissions aggregated with routine emissions from the site, plus emissions from any operationally related facilities, and background ambient levels from other sources. Otherwise, the authorized MSS emissions may not be protective of public health and welfare."

The commission has not changed the rule in response to this comment. The reasonably conservative impacts analysis performed by the commission establishes limits which are very protective. When releases occur from planned MSS, such as blowdowns or tank degassing, the short-term quantity will most likely be the most culpable source during that time, and therefore other operational releases will be dampened out by the higher, faster, releases.

EDF commented that the "TCEQ should expand the radius for aggregation of emissions for the protectiveness review beyond the proposed 1/4 mile distance. This radius should be sufficiently large so that the contribution of an upwind source becomes *de minimis* to a particular receptor when considered in combination with emissions from a downwind OGS."

The commission has not changed the rule in response to this comment. The commission has determined it is important that a distance cut-off is appropriate to capture the sources which are the most likely to contribute to a specific project under review.

TXOGA included "Examples of how the Proposed PBR and the Proposed Standard Permit are overly prescriptive and onerous compared to other PBRs and standard permits adopted by the TCEQ are numerous, but are highlighted by Proposed §106.352(b)(6)(B) and Subsection (b)(6)(B) of the Proposed Standard Permit, which would require OGS to conduct a case-by-case health impacts evaluation. The case-by-case evaluation and demonstration of compliance with ambient air standards and effects screening levels ("ESLs") that would be required by those proposed Subsections would be legally inappropriate to include as a condition of the Proposed PBR or Proposed Standard Permit since to do so would not be in "in harmony with the general objectives of the Act involved. TCEQ's air monitoring and toxicological studies have demonstrated that the current PBR establishes requirements that, if followed, result in insignificant contributions of air contaminants to the atmosphere. The proposed additional case-by-case evaluation provides no additional environmental benefits, but greatly increases the complexity of the OGS PBR and standard permit, and is, therefore, arbitrary and unreasonable. Furthermore, the TCAA clearly indicates that the Legislature intended for TCEQ to establish different levels of review and complexity for PBRs, standard permits, and individual permits. To require a facility to undergo a case-by-case evaluation of health effects in order to qualify for a

PBR and/or a standard permit would make the review processes for the different authorizations strikingly similar in many important respects (i.e., the process for PBRs, standard permits, and individual permits would be equalized with regard to the case-by-case review). Thus, adopting the Proposed Rules would in important respects "equalize" the different permitting mechanisms. Equalizing the permitting mechanisms would not be in harmony with the legislative intent that can be gleaned from the plain language of the statute - which is to distinguish PBRs, standard permits, and individual permits from each other. Thus, TXOGA urges TCEQ to remove the requirement in the Proposed PBR requiring a case-by-case health impacts evaluation in proposed §106.352(b)(6). For the same reasons, TXOGA urges TCEQ to also remove the case-by-case requirements for a health effects evaluation in Subsection (b)(6) of the Proposed Standard Permit."

The commission respectfully disagrees with the comment, but seriously considered eliminating the modeling options for protectiveness evaluations. The options considered included established definitive hourly limits under which all facilities must comply, but found that the values which would need to be established were unrealistically low and would result in a rule which would not be useful. Secondly, the commission considered relying solely on the developed Tables, but realized that due to the unique and varying nature of the oil and gas industry, the use of the Tables may be too conservative in some instances and inappropriately limit emissions. Thus, the commission determined that modeling demonstrations are appropriate options to demonstrate compliance.

EDF stated that the "TCEQ should develop a more comprehensive system for ensuring that emissions from proposed OGS, when combined with emissions from sources already in operation near a proposed oil and gas site, do not cause or contribute to exceedances of NAAQS or ESLs. As an initial step towards such a system, the TCEQ should modify the equations in Table 1 to account for existing ambient concentrations of relevant pollutants in the vicinity of a proposed site. Specifically, the TCEQ should substitute P and ESL in the equations with a variable to represent the difference between a NAAQS (or ESL) and recent monitored levels of the relevant pollutant in the area. Where no such monitoring data is available, TCEQ could provide default values."

Background concentrations are not required and were not developed for this project. The protectiveness review considered the impact from only the sources seeking authorization through the PBR and standard permit. Reasonable worst-case scenarios, emission caps, distance limitations, and inherent model assumptions combined with the use of maximum concentrations mitigate the need for background concentrations. Furthermore, ESLs are contaminant-specific air concentrations set to protect public health and welfare and include an adjustment factor to address cumulative and aggregate exposure.

The commission points out that the maximum modeled concentration typically occurs in a relatively limited area, as compared to the entire modeling domain. In particular, for the short-term averaging periods, such as the one-hour averaging period, modeled concentrations across the modeled area generally show that

ground level impacts are reduced significantly from the peak value as the pollutant travels a relatively short distance from the source, so that the peak modeled concentrations represent the source's impact at only a relatively few receptors within the modeled area. In addition, it is important to note that the temporal and spatial conditions which lead to a maximum impact by one source are seldom the same for other sources, such that maximum impacts of individual sources do not typically occur at the same location or at the same time.

EPA notes that "TCEQ used the ISCST3 model, and claimed that the predicted ground-level concentrations were conservative especially for short distances and low-level emissions. In the modeling community this is thought to be the case based on some model comparisons between AERMOD and ISC but most of those comparisons were not for Oil and Gas facilities. Oil and Gas facilities are a unique combination of low-level point and fugitive source/emission types with relative close property boundaries. TCEQ's modeling scenario matrix should be run with AERMOD to verify that the values obtained with ISC are conservative."

AERMOD is EPA's preferred model for major NSR; that is, those new major sources or major modifications to existing major sources that trigger federal review. Since the Oil and Gas projects authorized under PBR or standard permit cannot be major, the commission used the ISC to conduct the protectiveness review. The commission uses the ISC model for minor source permitting. The commission does not require the use of AERMOD for minor projects for two primary reasons: ease of use and continuity. The ISC model has been used in

permitting for more than 20 years. The model was developed to be easy to use and address complex atmospheric processes in a relatively simple way that can be understood by all users. The use of ISC provides a basis for technical consistency with other minor permit reviews (for all contaminants) at a site. However, once an applicant has used AERMOD, the TCEQ requires the use of AERMOD for major and minor projects at the site to ensure consistency of review.

AERMOD was developed to address complex atmospheric processes in a more refined way but the basis of the model and associated pre-processors and meteorology are not easily understood. Unlike ISC which has been vetted and improved over time, EPA promulgated AERMOD with known shortfalls but no formal plan to address them.

In addition, AERMOD is unnecessarily complex for general use. Since the protectiveness review for the PBR and standard permit applies anywhere in the state, the use of AERMOD would have presented many technical challenges that would outweigh any refinements in predicted concentrations. For example, input to AERMET, the meteorological processor for AERMOD, requires complete upper-air soundings and values for surface characteristics such as roughness length, Bowen ratio, and noontime albedo. These surface characteristics are not observed but must be estimated.

The values for these characteristics vary with location and time of year. To

account for all the variations in these surface characteristics across the state, an impractical number of combinations of values would be required for evaluation. ISC accounts for surface characteristics by the use of either urban or rural dispersion coefficients. The protectiveness review was based on the most representative coefficient.

EPA expressed concerns with the "minimum exit velocities for engines and turbines stacks of 159 ft/sec and 315 ft/sec. In reviewing information for engines and turbines for the types of sources that would be covered by this PBR and standard permit, we have noted actual stack data with exit velocities more often in the 75 to 150 ft/sec, with only a small percentage of the engines having exit velocities greater than 315 ft/sec. The higher stack velocity will give more momentum to the plume and thus lower near field concentrations. We believe the modeling analysis supporting the PBR and standard permit should either be redone for minimum velocities of 60 - 75 ft/sec or a lower value that will capture the minimum stack velocity based on TCEQ's review of stack data. Since exit velocity is a critical parameter in the modeling, the PBR and standard permit should have the source verify that their stack velocity is greater than the minimum velocity in order to use the PBR or standard permit. We believe that the minimum thermal temperature should also be used otherwise they should be going through normal permitting and modeling review."

The dispersion modeling conducted for the protectiveness review was based on the information the commission had available at the time the analysis was performed. Additional information regarding various sizes of engines has been received since

this analysis was performed. This information was used to modify the engine table. In addition, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address this concern.

EDF commented that the "TCEQ should provide data to support its assumptions about the flow rate and stack velocities used in the dispersion modeling, and make appropriate adjustments if necessary to reflect real world conditions. The TCEQ should rerun the dispersion model for engines with the adjusted assumptions and revise the unit values in Tables 3 and 4. In addition, to ensure real world operating conditions match the assumptions used in the protectiveness review, the TCEQ should add a condition to the draft OGS standard permit and PBR rules that limits engine and turbine exhaust exit velocities to a minimum of 159 ft/sec for small engines and 315 ft/sec for large engines (these are the exit velocities used in the TCEQ's modeling; or alternative values if TCEQ reruns the dispersion model with new exit velocities based on our comment), and requires periodic sampling and demonstration of compliance that such a limit is being met."

The dispersion modeling conducted for the protectiveness review was based on the information the commission had available at the time the analysis was performed. Additional information regarding various sizes of engines has been received since this analysis was performed. This information was used to modify the engine table. In addition, the commission will allow the applicant to conduct modeling with a screening or refined model that follows a prescribed protocol to address

this concern.

EDF commented that the "TCEQ should remove the proposed options for applicants to submit their own screening or dispersion modeling. Such modeling would not be subject to public review and create an unnecessary strain on agency resources. If TCEQ decides to allow such modeling demonstrations, then the rules must explicitly include the instructions that applicants must follow (after appropriate administrative rulemaking procedures -- otherwise the public would not be allowed the opportunity to review and comment). In addition, if TCEQ allows applicant modeling, then it must be prepared to ensure the modeling section will review all dispersion modeling submitted for an OGS PBR or standard permit, and increase application fees accordingly."

The commission has not changed the rule in response to this comment. Modeling will be accepted under the new PBR, and not every registration will be reviewed. Instead, random audits of modeling demonstrations will be performed to ensure quality data and results. In all cases, applicants must follow very specific protocols for using modeling as a demonstration technique and the rule also requires these submittals to be part of a certified registration.

Devon commented that, "The timing of the proposed rules does not consider the results of recent air quality studies in the Barnett Shale, including studies conducted by the TCEQ, that concluded no pollutants from OGS were found at levels of concern. Further, the proposed rules do not consider the ongoing emission inventory initiatives in the Barnett Shale, which would help inform the rulemaking process."

The emissions monitoring and inventory in the Barnett Shale are not directly relevant to this rule action. The inventory addresses the need to have a comprehensive picture of all oil and gas operations in the area of interest, something not possible under the current PBR or standard permit. The monitoring addresses ambient conditions from a cumulative basis to ensure that groups of facilities are not contributing to problems in particular locations.

TPA commented that, "Over the course of the last year, there has been much public concern expressed over the potential or perceived impact of natural gas production, gathering, and transmission activities in the Barnett Shale area, particularly in and around the urban areas. While there have been publicly funded health studies and numerous ambient air quality studies performed by private consultants, the TCEQ, and other publicly funded organizations, none yet have indicated chronic, long-term, adverse health effects due to these activities. TPA considers protection of public health to be its utmost concern and understands the interest of the TCEQ in ensuring that oil and gas operations in and around the Barnett Shale demonstrate protectiveness. However, a state-wide remedy is not justified or needed to address a potential regional concern. Indeed, the Texas Oil and Gas Association ("TXOGA") has performed an analysis that demonstrates that even though the number of wells in the 9-county DFW nonattainment area has grown over the past 10 years, ozone levels have dropped. See chart entitled Number of Barnett Shale Wells versus Eight-Hour Historical Ozone Levels versus Population in the 9 County DFW Non Attainment Area, attached hereto as Exhibit A.

Accordingly, with no demonstrated harm from these activities, the TCEQ may not have a rational basis to implement the full panoply of revisions to the OGS PBR and standard permit in the Barnett Shale area and certainly is not justified in requiring the full implementation of these revisions across the state."

The commission has not changed the rule in response to this comment. As with other operational scenarios covered under this PBR, control requirements are not stipulated, only options, if emissions cannot meet standards, guidelines, and limits.

EDF stated that the "TCEQ's modeling for compressor blowdowns and pipeline purging stacks does not consider stack-tip downwash, which is a non-regulatory default option in AERMOD and ISCST3. The TCEQ included stack-tip downwash for all other modeled point sources. Excluding stack-tip downwash from the modeling study ignores the effects of turbulent eddies that form immediately downwind from a stack. The AERMOD Implementation Guide (revised March 19, 2009) states that stack-tip downwash should be turned off for capped or horizontal stacks that are not subject to building downwash. However, the compressor blowdown and pipeline purging stacks were not represented as horizontal or capped stacks. If stack-tip downwash were included in the model, the Table 6 predicted concentrations from pipeline purging would increase dramatically (blowdowns were unaffected). Our consultant, Source Environmental Sciences quantified the increase in predicted concentrations due to the inclusion of stack tip downwash. For example, using AERMOD with Travis County met data, the unit concentrations at a receptor 50 feet away from the purging of gas pipeline at a height of 10 feet increase from 1,285 without stack-tip downwash to 43,819 with stack-tip downwash, a factor of 33 higher. The full results of this analysis are included in the tab "Table 6.1" in the spreadsheet entitled "O&G Tables Comparison.xls"."

The commission's review accounted for reasonable worst-case conditions with consideration given to general air dispersion model assumptions and operational scenarios. The ISC model was developed with assumptions such as: continuous, unvarying emissions; no removal of mass from the plume; steady-state conditions; and no downwind dispersion. In addition, EPA has included equations to calculate a number of effects on plume dispersion such as stack-tip downwash. The basis for stack-tip downwash was a study conducted in 1941 to determine the cause of downwash of stack gases at a power plant in Chicago. While EPA incorporated the equations into ISC and has provided limited guidance on their use, the commission does not believe their use is appropriate for short-duration, non-continuous, low-level releases.

In addition, the small diameter of the stack (6 inches) would not likely be affected by aerodynamic affects such that a low pressure area develops on the downwind side leading to the associated stack-tip downwash affect.

Subsequent review of the pipeline blowdowns parameters used in the modeling analysis were determined not to be representative of the activities occurring. Specifically, the 6-foot diameter was not representative. The compressor

blowdown parameters were determined to be representative for both pipeline and compressor blowdowns.

Devon expressed concerns that "the decisions with respect to the timing and stringency of the proposed PBR have been made without consideration of the many current and pending federal actions, including: The National Emissions Standards for Hazardous Air Pollutants (NESHAP), Subpart ZZZZ existing engine rule finalized in August 2010; The new one-hour NO_2 National Ambient Air Quality Standard (NAAQS) finalized in February, 2010; The new ozone NAAQS that is expected to be finalized in late 2010; The Greenhouse Gas Mandatory Reporting Rule, Subpart W, covering oil & gas facilities that is expected to be finalized in October 2010; The review of many additional oil and gas New Source Performance Standards (40 CFR 60 NSPS) and NESHAP requirements (including Subparts KKK, LLL, HH, and HHH) under consent decree, which are expected to be proposed in January 2011; Moving ahead of the federal regulations too quickly could result in conflicting and unnecessary regulations which could prove problematic to the TCEQ and the regulated community."

TXOGA stated that facilities that do not change the certified character or quantity of emissions should not subject to the BMPs. TXOGA also noted that the requirement in the proposed rule conflicted with the proposed (b)(5)(B) that stated "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."

The commission has revised subsection (b)(5) in response to this comment to clarify which projects trigger the requirements of the rule (including BMP).

Adopted subsection (b)(5) excludes changes to existing facilities that do not change the character and do not increase the potential to emit over previously certified emission limits.

ETC commented that, "The Best Management Practices and Minimum Requirements provisions should be revised. As stated elsewhere in these comments, modifications that do not change the character or increase the quantity of emissions should not trigger coverage by the provisions of the new oil and gas PBR. The language in the proposed PBR is currently subject to the interpretation that the BMP requirements would apply to facilities or groups of facilities at a project even if those facilities are not changing the character or increasing the quantity of their emissions. The confusion originates from language in subsection (e)(1), which states that "{e}ach site shall establish and maintain" a BMP program. Subsection (e): Add the following sentence to the end of subsection (e): "The requirements in this subsection (e) are not applicable to existing facilities at an OGS that are not part of the project triggering registration under this section.""

TPA commented that proposed subsections (e) and (f) on operating and control requirements "are too onerous. Proposed subsections (e) and (f) of the proposed PBR prescribe various detailed and extensive operating and control requirements to which facilities must adhere. As noted elsewhere in these comments, TPA believes that such prescriptive requirements are inappropriate, and that the standards should focus on compliance with emissions limits, not detailed prescription of the particular means by which compliance is achieved. Satisfaction of the general emissions limits set forth in the PBR and Standard Permit should be sufficient. If

TCEQ intends to retain specified operating and control requirements, then the agency should understand that many of the proposed requirements would require the outlay of substantial effort and money. Accordingly, the agency should provide *de minimis* emission thresholds below which such requirements would be inapplicable. TPA believes that many of the requirements set forth in proposed subsections (e) and (f) are far too burdensome and prescriptive for inclusion in a PBR, which by definition is reserved for facilities that "will not make a significant contribution of air contaminants to the atmosphere (see THSC, §382.05196). TCEQ has taken the position that "{a} permit by rule is the state air authorization for activities that produce more than a *de minimis* level of emissions but too little for other permitting options," but the currently proposed operating and control requirements are inconsistent with this concept." Kinder Morgan stated the "Prescriptive requirements in subsection (e) and (f) are unrealistic and can cause unintended increases in emissions and significant expense to industry. The fact that the PBR would prescribe a host of detailed control and operating requirements is a major issue. Such prescriptive requirements are unnecessary. If a site meets the overall emissions limits requirements set forth in the PBR, then that is all that should matter; the particular means by which the site is able to meet those limits is irrelevant to the environment and it should be irrelevant to the TCEQ. The inclusion in the PBR of numerous pages of detailed control requirements inject unnecessary confusion and complication and make it harder for the regulated community to determine whether or not a PBR could be claimed." ETC "objects to the over-reaching host of controls and requirements that would be prescribed on the Texas oil and gas industry by the PBR and believes them to be unnecessary in this proposed rule. If a site meets the overall emissions limits requirements set forth in the PBR to demonstrate protectiveness, the particular means by which the site is able to meet those limits should be irrelevant. The inclusion in the PBR of pages of unnecessary control requirements will only create confusion and increase costs, with no corresponding benefit to public health or the environment."

ETC also stated that, "The proposed operating and control requirements for PBRs are overly burdensome and prescriptive. Proposed §106.352(e) and (f) prescribe various detailed and extensive operating and control requirements to which facilities must adhere. As noted elsewhere in these comments, ETC believes that such prescriptive requirements are inappropriate in the PBR, and that the standards should focus on compliance with emissions limits; not detailed prescription of the particular means by which compliance is achieved. If health impacts are not an issue for a specific site, satisfaction of the general emissions limits for PBRs (25/250 tpy) should be sufficient. Many of the requirements set forth in the proposed subparagraphs (e) and (f) are overly burdensome and prescriptive for inclusion in a PBR, which by definition is reserved for facilities that will not make a significant contribution of air contaminants to the atmosphere. TCEQ has taken the position that "{a} permit by rule is the state air authorization for activities that produce more than a *de minimis* level of emissions but too little for other permitting options," but the currently proposed operating and control requirements are completely inconsistent with this concept."

Targa stated "In addition to Targa's comments on the broad controls being required on unaffected equipment, Targa feels the control requirements being introduced in the proposed PBR go well beyond what Best Available Control Technology (BACT) standards would require if these small emission sources went through case-by-case NSR permits under 30 TAC Chapter 116. The PBR should not contain prescriptive controls; the only consideration should be that the site meets the PBR's emissions requirements, regardless of the particular means by which this is achieved. Targa understands that the TCEQ needs the PBR to be protective, but would like to recommend removing the prescriptive control requirements at PBR sites. These sites should have small potential emission rates as required in the site-wide emission limitations as well as the speciated emission rate tables. Not limiting how a site controls its emissions, in order to meet the site wide emission limitations of the PBR, would allow for more innovative control techniques. Larger emission sources already implement control requirements to reduce emissions below the PBR thresholds."

The commission has revised the rule language to state BMP requirements are not applicable to existing, unchanging facilities at an OGS. The commission is also clarifying that controls specified in the BMP requirements are not required unless a company chooses to certify the controlled emissions or if it needs to implement controls to meet the emission limitations of the PBR. The commission is requiring companies to certify emissions when a control is needed to meet the emission limitations because the emissions would not be insignificant if the control did not work properly. Proper expectations for the controls are imperative for allowing the oil and gas industry to use the PBR for the vast majority of the production operations.

Pioneer commented that, "Facilities that do not increase the previously registered or certified emissions or potential to emit should not be subject to section (e) Best Management Practices. This triggers difficult BMPs that require expensive retrofits and replacements to other equipment at the site, as well potential monitoring programs. Further and most important, this provision discourages replacing equipment with newer equipment, such as more efficient engines that reduce emissions, or adding emission reduction equipment. It also discourages replacing equipment due to safety or integrity concerns."

The commission's goal is to minimize emissions. Technical and economic considerations are the main drivers that minimize emissions. Efficiency is not the primary consideration. Additionally, a replacement facility is a new facility. The commission has determined that replacement facilities are new facilities that, at a minimum, must meet BMPs and that replacement facilities must meet BMPs even if emissions are reduced or unchanged. The commission is not aware of how BMPs discourage efficiency. In a follow-up discussion by phone with Pioneer on October 22, 2010, Pioneer indicated the reason that BMPs discourage replacements with more efficient equipment because BMPs are still applicable even if the emissions remain the same or are reduced. The commission is not aware of any specific safety and integrity concerns due to BMPs, and the commission would need more details about specific concerns. Only the minimum BMPs in subsection (e)(1)(A) - (C) are required for new facilities. Companies choose to follow any of the remaining BMPs in subsection (e)(6) - (12). If a company chooses to control emissions using one of the additional methods to meet an emission limit in the PBR, then the company must follow the requirements of the selected BMP.

TPA commented that, "Subsection (c)(1)(C) - Facility replacements that do not increase potential to emit should not trigger applicability of BMPs. As currently proposed, subsection (c)(1)(C) of the PBR would subject replacement of any facility — including a like-kind replacement (see 35 TexReg 6948 (2010) (stating that "{p}roposed subsection (c)(1)(C) covers like-kind replacement of existing facilities under very specific circumstances") — to the best management practices ("BMP") requirements set forth in subsection (e). This provision is in direct conflict both with subsection (e) and with the preamble, each of which makes clear that TCEQ does not intend for BMPs to apply to existing facilities that are not changing the character or increasing the amount of emissions. See, e.g., proposed subsection (e) (limiting the applicability of subsection (e) to new or changed facilities where such changes increase emissions); see 35 TexReg 6949 (2010) (stating that subsection (e) is "not applicable to existing, unchanged facilities at an OGS"). The policy expressed in subsection (e) and in the preamble is well-founded: if a replacement does not change the character or increase the amount of emissions and is a continuation of prior practices, then it should not be subject to BMPs. Such a requirement is not justified for replacements, whether like-kind or otherwise, that do not increase a facility's potential to emit. For all practical purposes, such a "change" represents a continuation of prior practices and does not represent an increase in amount or character of emissions."

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Like-Kind changes have no impact on emissions. Strike from rule, §106.261 (5 tpy threshold) reiteration, §106.264 replacement of facilities for like-kind changes, §106.8 recordkeeping already requires records and is redundant. Please remove from the rule. Records on equipment specifications and operations, including summary of emissions type and quantity."

The commission notes that the like-kind replacement of oil and gas facilities under state statute and federal regulations has always considered replacement facilities to be new facilities. The oil and gas industry in Texas has been operating under a policy exception memo that allowed this industry to replace like-kind components without seeking any new authorization until a regulation update occurred. As specifically stated in the September 1, 2005 memo from Mr. Glenn Shankle, the former executive director of the TCEQ, to the Air Permits Division, this policy "does not apply to any other industry or facility type." This memo is being rescinded and replaced with this adopted rule. Thus, the oil and gas industry must, like all other industries regulated under TCEQ rules, consider like-kind replacement of facilities to be new facilities or modifications to existing facilities. The commission has revised the rule language to more accurately reflect its intent. The commission is not requiring companies to register new replacement facilities if they do not increase the previous actual or certified emissions, but does expect replacement facilities to comply with the required minimum best management practices in subsection (e)(1)(A) - (C). The BMP requirements are required as a reasonable set of standards to ensure that these new facilities are well operated and maintained to minimize emissions. Since this rule specifically evaluated oil and gas facilities, the commission has also determined that it is inappropriate to rely on a generalized PBR for replacements and §106.264 cannot be used.

BMP

EDF recommends "the following BMP: Plunger Lifts and "Smart" Well Automation during Well Unloading. Operators often remove unwanted fluids from mature gas wells through "well unloading"- practices that lead to venting of methane, HAPs and VOCs. One way to remove unwanted fluids without venting while also improving well productivity is to install a plunger lift system and "smart" well automation system. Plunger lifts use gas pressure buildup in the well casing-tubing annulus to operate a steel plunger that pushes liquids to the surface. Smart well automation maximizes the efficiency of plunger lifts by routinely varying plunger well cycles to match key reservoir performance indices. Natural Gas STAR partners have reported annual gas savings averaging 600 thousand cubic feet ("Mcf") per well and increased gas production of up to 18,250 Mcf per well, worth an estimated $127,750 through the implementation of plunger lifts. Installing smart well automation on plunger lift systems typically results in an average savings of 500,000 cubic feet of methane per well, per year."

The commission appreciates the information and will look into sharing the information in the Pollution Prevention outreach programs. The technology had not been evaluated by the TCEQ in sufficient detail and would expand the scope of the proposed rule. Therefore, the commission is not including plunger lifts and "smart" well automation during well loading in the adopted rule. However, companies have the option to choose such systems to control emissions wherever they are economically reasonable.

TPA suggesting revising the first two sentences in subsection (e)(1) as follows: "All facilities that are a part of the project triggering registration under this section which have the potential to emit air contaminants must be maintained in good working order and operated properly during facility operations. Each site facility subject to this subsection shall establish and maintain a program to replace, repair, and/or maintain facilities to keep them in good working order."

The commission has made equivalent changes to subsection (e) to clarify that BMP is only applicable facilities related to a project.

SWEPI commented on "demonstration of best management practices by a maintenance program and records management, such as glycol solvent maintenance, glow plug maintenance, corrosion control, and burner maintenance, should provide adequate control to demonstrate rated emissions performance. The addition of a temperature indicator (TI) and recorder on the glycol condenser offers no added emissions controls benefits if the condenser system can be verified as closed with P&ID's. The company is proposing that best management practices demonstrated by a maintenance program and records management should provide adequate control to demonstrate rated emission performance. The addition of a temperature indicator and a recorder to the condenser on a closed (no exhaust to atmosphere) glycol dehydrator system."

The commission is not changing the rule in response to this comment. Best management practices support good repair of the equipment at the site and will allow the equipment to perform its proper and rated function. However, it does not guarantee that the equipment will consistently run properly, which could result in excess emissions. Properly operating capture, recovery, and control

equipment in good working order is essential to ensure that facilities are meeting authorization limits. As equipment ages, there is tendency for it to be less efficient and create more emissions. This is primarily true for equipment involving moving between parts. The rule does not require emissions from the flash tank and the reboiler (or reboiler condenser) vented to a VRU, Flare, or Thermal Oxidizer that is designed to be on-line at all times the glycol dehydrator is in operation, the control system monitoring (no temperature indicator) for the glycol dehydrator is not required.

ETC commented that, "This subsection requires companies to set up a site maintenance plan that is specific to each and every oil and gas site and keep associated records. This requirement is overly burdensome and restrictive. TCEQ should provide the option for development of generic maintenance plans that are applicable to multiple facilities as a way to reduce the burden of this best management practice (BMP). This subsection also requires companies to follow manufacturer's specifications to ensure that equipment is operated properly. Manufacturer's specifications are written for warranty purposes and are designed to limit the liability of the manufacturer. These specifications are not written as operational standards or limitations. Nearly all equipment can be safely and efficiently operated within a range that is outside of the manufacturer's specification requirements. It is not appropriate to base a BMP on such specifications."

TPA commented on subsection (e)(1)(A) (PBR and Standard Permit) "Manufacturers' specifications and recommended programs must be followed. This requirement would mean that companies would have to set up a site maintenance plan that was individual to each and every oil and gas site and keep associated records, all of which would be very burdensome. Manufacturers' specifications are generally set in a conservative manner because they are designed to protect the manufacturer from warranty claims and to generate revenue for the manufacturer. It would not be appropriate to base a best management practice on such specifications. Rather, facility operators should be allowed to determine their own maintenance requirements based on their experience operating their equipment."

Exterran stated that, "In both the Proposed Standard Permit and the PBR, TCEQ should allow the use of owner/operator maintenance programs "in lieu of" manufacturer's recommend programs. Owners and operators have a vested interest in maintaining engines consistent with technological limitations and good engineering and maintenance practices. Both proposals currently require any "new facility, group of new facilities or changes to existing facilities that increase the PTE or increase any emissions at a previously authorized facility" at an OGS site to establish a program that includes "Manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions." Proposed Standard Permit subsection (e)(1)(A) and Proposed PBR §106.352(e)(1)(A). We request that TCEQ amend both the Proposed Standard Permit subsection (e)(1)(A) and Proposed PBR §106.352(e)(1)(A) to add the following language: "manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions or, for engines, in lieu of manufacture specifications and recommendations, an owner or operator may develop and follow a maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions." This provision is consistent with the recent NESHAP maintenance requirements imposed on SI RICE that require catalytic controls. 40 CFR §63.6625(e). Final 2010 NESHAP, 75 FedReg 51570 at 51590 (August 20, 2010)."

Devon commented that, "The proposed rule requires each site to establish and maintain a program to replace, repair, and/or maintain facilities in good working order and shall include manufacturer's specifications and recommended programs applicable to equipment performance on emissions. This requirement should be deleted entirely or, in the alternative, expanded to allow the use of "owner/operator best management practices"."

EDF stated that "the BMP requirements should be revised to read: "Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions"

The commission agrees with the comments and has changed the rule language to clarify that any maintenance program established by a company is acceptable, and where manufacturer's guidance on such maintenance has a direct correlation to emissions.

EDF commented that the rule should be changed to read: "cleaning and routine inspection of all equipment."

The commission has revised the rule language to include routine inspection of

equipment.

Pioneer stated that "a replacement facility may not be able to meet the "50 feet from any property line or receptor" limitation in the BMP section (e)(3) due to subsequent building of receptors since the existing facility was constructed. Please add "replacement facility" as an exception to the "50 feet to any property line or receptor" limitation in the final rule."

Subsection (e)(2) states, "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: subparagraph (C) existing OGS facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50-foot requirement. Replacement facilities must meet all other requirements of this section." This requirement specifically recognizes that certain replacement facilities may not be able to meet the 50-foot set-back requirement. However, the commission will not grant a general exception to all facilities that are replacing previously authorized facilities that are located less than 50 feet from a property line or receptor. An operator must be able to demonstrate that good engineering practices would not allow the replacement facility to be moved to meet the 50-foot set-back. Only after such a demonstration would the exception to the 50-foot set-back requirement be acceptable for the replacement facility.

Parrish Field Services commented that, "To the extent that TCEQ is convinced that minimum distance limits on receptors and/or the property line is necessary, NorTex endorses those included in the proposal. As was noted by the Sierra Club in the public meeting, cities have the option of adopting restrictions on the location of oil and gas facilities, so the 50-foot distance limit proposed by TCEQ may not be necessary. However, if the agency concludes that public health cannot be protected absent some minimum distance, the 50-foot distance is preferable to an attempt to match limits adopted by one city or the other."

The commission appreciates the support.

Senator Davis commented that, "The separation distance should be increased from 50 feet to 200 feet and 600 feet for new wells. This separation is more consistent with other states' regulations (New Mexico). A variance should be available to local government for modifications based on specific circumstances."

The Sierra Club and 134 individuals requested to increase the minimum separation to receptors from 50 to 250 feet. The Sierra Club also stated that "the distance is simply not sufficiently protective of public health and welfare."

TRAED and 5 individuals stated that, "Separation to receptors should be 250 feet and 500 feet would be better for the public."

Five individuals and Earthworks Texas Oil and Gas Accountability Project stated that, "Many municipalities have adopted 500-foot setbacks for industrial installations to protect their population. Industry has moved into the unincorporated areas to avoid these setbacks, and some of the oldest OGS are located next to residences and schools in these areas. TCEQ regulations are the only protection in these areas, and a 50-foot setback is not sufficient to provide protection from an OGS containing up to 40 pieces of equipment."

The commission has not changed the rule in response to this comment. Due to the unique nature of the oil and gas industry and the potential and historical location of various facilities, and based on the protectiveness review completed, the commission does not agree that 100 feet to 600-foot buffers are appropriate or necessary. Depending on the type and quantity of emissions released, distance limits for particular combinations of facilities are established by compliance with subsection (k). Local ordinances in cities and towns can establish greater distance limitations and have the option of adopting restrictions on the location of oil and gas facilities in their jurisdiction.

EDF commented that, "New OGS facilities should be no closer than 100 feet from any property line or receptor, instead of the proposed 50 feet to account for potential uncertainties in dispersion modeling at short distances under calm wind conditions."

The commission has not changed the rule in response to this comment. Treatment

of calm or light and variable wind poses a special problem in model applications since steady-state Gaussian plume models assume that concentration is inversely proportional to wind speed. During conditions of calm winds, one would not expect pollutants to disperse over a large area. Generally, concentrations become unrealistically large when calm winds are input to the model. Procedures have been developed to prevent the occurrence of overly conservative concentration estimates during periods of calms. These procedures acknowledge that a steady-state Gaussian plume model does not apply during calm conditions. Model limitations were taken into consideration when determining the predicted concentrations at 50 feet. In order to account for potential uncertainties in dispersion modeling at short distances under calm wind conditions, the results for all sources at 50 feet were set equal to the maximum predicted concentration occurring at any distance. For example, the maximum predicted result for the 1-meter fugitive is 4,375 µg/m^3 and occurs at the 100 feet receptor. Even though the model prediction for the 50 feet receptor was less than 4,375 µg/m^3, the results listed in the table is 4,375 µg/m^3.

Pioneer requested clarification in the rule or preamble on "whether movable engines meet the definition of "immovable." For instance, engines consist of multiple parts: the base or concrete pad the engine may sit on, the piping that connects to the engine, and the combustion portion of the engine. The concrete pad and piping are typically not movable and are part of the engine, whereas the engine itself may be easily swapped out with another engine. If the engine has a permanent concrete pad or piping, it should be considered immovable and therefore, an exception to the "50 feet from any property line or receptor" limitation."

The commission has added language to the rule to allow replacements of existing facilities within 50 feet of property lines and receptors. If the facility is modified or replaced, the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50-foot requirement. Replacement facilities must meet all other requirements of this section. Whether an engine is "movable" or "immovable" is not the basis for determining if an engine is "permanent." However, the commission will not grant a general exception to all facilities that are replacing previously authorized facilities that are located less than 50 feet from a property line or receptor. An operator must be able to demonstrate that good engineering practices would not allow the replacement facility to be moved to meet the 50-foot set-back. Only after such a demonstration would the exception to the 50-foot set-back requirement apply to the replacement facility. The commission has a rule air rule interpretation summary memo that describes when an engine is considered a stationary source and needs an authorization. The memo states that "a portable or transportable engine which remains or will remain at a single point or location less than or equal to 12 consecutive months is not considered a stationary source and no authorization under Chapters 106 or 116 would be required." This rule interpretation memo may be revised in the future.

TPA stated that subsection (e)(3)(C), "That subsection should be struck in its entirety as it is unclear what would be required if the facilities were movable and unfixed. The provision basically establishes a 50-foot setback from any property line or receptor but states that it does not apply to, among other things, "existing, immovable, fixed OGS facilities which were constructed and previously authorized, even if modified." It sets up a question of fact as to whether facilities are movable or not without consideration to costs, engineering design and other factors. The provision over complicates what should be a simple authorization mechanism."

The commission has revised the rule in response to this comment. The new requirement specifies when companies modify or replace a facility, "the owner or operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50-foot requirement . . .." The commission will maintain guidance as to what is reasonably considered immovable. The commission encourages companies to move existing facilities that are within 50 feet, but is aware that there could be legitimate safety concerns in some instances for not moving a facility.

Specific control equipment

TPA commented that, "The prescribed engine control requirements are of particular concern. Many of the standards being proposed are the sort of stringent requirements that apply to NSR permits that are more comprehensive than PBRs, and the control technology requirements currently being proposed meet or exceed MACT and 40 CFR Part 60 NSPS standards. As currently proposed, the PBR's requirements are akin to the sort of controls placed on engines in nonattainment areas. It is not appropriate to include such stringent controls in a PBR that: 1) has state-wide application; and 2) is meant to apply to relatively insignificant emission sources."

JLCC commented that they have "been using a liquid catalyst (not SCR) (no urea) in conjunction with a patent-pending pump to successfully reduce the NO_X emissions to <0.5 G/hp-hr on CAT Lean Burn Engines. The average cost per installation is $3,000 one- time payment for equipment lease and $700-$1,000/month for liquid catalyst on a 3516 CAT. Reductions in NO_X were 3.76 - 4.75 tpy based on average of 3rd party tests (CAT 3516). Also achieved VOC, CO reduction and a reduction in fuel use. There were lower maintenance costs on equipment with virtually no carbon or ash build-up on engine components after using the liquid catalyst. This offers a low-cost alternative."

The commission did not prescribe any particular specific control technologies on engines. Emission limits were set allowing for the vast majority of engines to continue operation unchanged until such time as they are replaced. The dates for older engines to meet certain emission limits have been based on typical life cycles of those engine types as provided by various stakeholders. Companies are not required to upgrade catalysts until 2020, or replace engines or turbines to meet the standards until 2030. Since companies will amortize capital costs over a 10-year period, and the closest standard date is in 10 years, there will be no new actual costs to meet the standards in the new rule. At the time the catalyst, engine, or turbine is replaced, it will be at the end of its normal operating life and will have depreciated such that there will be no choice than to replace it.

However, if an applicant proposes to use the referenced control, the commission will review it and approve the application if all other parts of the rule are met.

One individual stated that they "Recently filed an odor complaint with TCEQ regarding diesel exhaust emissions. The odor was so bad it required that he put his family in a motel for the evening. The report from TCEQ stated that "continuous operation of three diesel generators greater than 400 hp at this site resulted in significant emissions of nitrogen oxides. An estimate of maximum nitrogen oxide for one hour on a complainant's property using a screen model was 380 ppb. Aruba Petroleum should use nitrogen oxide controls on its diesel engines as his family was exposed to more than 10,000 years of nitrogen oxide in 2 months. Studies have shown that children on the Barnett Shale have an asthma rate of 25 percent versus a national average of 7 percent, and his daughter was recently diagnosed with the disease. He questions how many more will be diagnosed before TCEQ requires electric drills or diesel filters. Aruba has been found in violation of Title 30 and the THSC numerous times in the last year. He stated that TCEQ should not make it any easier on a bad operator than they obviously have it."

The commission will require applicants to demonstrate that all engines on site are protective of the all NAAQS, including NO_2. The current one hour NO_2 NAAQS is 188 $\mu g/m^3$. Under the adopted rule, the company will have to show it does not cause an impact greater than the NAAQS at any off-site receptor. Diesel engines subject to the proposed rule will be required to meet the current off-road engine standard, which will greatly reduce nitrogen oxide and particulate matter emissions compared to older engines.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that the "PBR should align with 40 CFR Part 63 Subpart ZZZZ, 40 CFR Part 60 IIII, or 40 CFR Part 60 JJJJ requirements. The PBR should allow for management practices instead of control requirements such as oil changes/analysis and spark plug check. There should be Intervals of 1440 hours as in the NESHAP. EPA already evaluated whether or not emissions limits were needed for small engines and determined through extensive evaluation that emission limits were not needed, only management practices. There are over 10,000 engines in Texas less than 500 hp. Complying with this requirement would cost the industry over $140,000,000. This adds additional burden and confusion to operators having different requirements from the federal requirements for these small engines."

ETC commented that in less than 2 years, all engines will be subject to either existing or new engine 40 CFR Part 60 NSPS regulations. Consequently, ETC believes the TCEQ should make the proposed PBR consistent with all federal regulations and require engines, glycol dehydrators, and tanks in ozone attainment areas to comply with the applicable 40 CFR Part 60 NSPS, NESHAP, and MACT requirements. Minor source glycol dehydrator emissions were recently reviewed by EPA under the "residual risk" review requirements. In addition, the EPA has agreed to review all major and minor source 40 CFR Part 60 NSPS and NESHAP regulations for the oil and gas sector and to propose any changes within a year. Accordingly, ETC stated that the PBR should incorporate by reference 40 CFR Part 60, Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ with the applicable tables cited, and should not prescribe requirements that go beyond federal law.

Exterran commented that, "As TCEQ noted in the preamble to the Oil and Gas Proposal, the cost, time and expense considerations for controlling the number of SI RICE in Texas will be very significant. These costs can be particularly oppressive and less cost effective for small SI RICE, especially when considered together with compliance costs for all SI RICE statewide. The Gas Compressor Association (GCA) estimates an industry cost of $146,000,000 just to meet the .5 and 1 g/hp-hr standard for 4-stroke rich-burn (4SRB) SI RICE under 500 hp in the Proposed Standard Permit and Proposed PBR, respectively."

Exterran also stated that, "Smaller RB SI RICE < 500 hp implementation should have a longer phase –in period in the Standard Permit and Permit by Rule (Section A)."

EPA Region 6 questioned whether the TCEQ has "considered the mandatory use of electric motors instead of internal combustion engines to drive natural gas compressors to reduce air emissions in nonattainment areas?"

The commission did not change the standard permit in response to this comment. The commission believes that mandatory use of electric motors would be untenable. There is a common issue of lack of electric service at remote sites throughout the state. The standard permit applies BACT requirements to all internal combustion engines, as well as federal combustion standards to the combustion sources affected by this standard permit.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that the "Control requirements on small HP engines represents a great impact to the industry, TCEQ should consider an exemption level similar to that of the East Texas combustion rules.408 TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Control requirements on small HP engines represents a great impact to the industry. TCEQ should extend the phase in dates for small HP."

The commission is not aware of any emission standards for gas-fired engines manufactured before 2007 in a 40 CFR Part 60 NSPS and specifically Subpart JJJJ. Therefore, the commission cannot rely on a 40 CFR Part 60 NSPS to establish emissions standards for these engines. Also, ozone nonattainment is not related to 40 CFR Part 60 NSPS, 40 CFR Part 61, 40 CFR Part 63 NESHAP, or 40 CFR Part 63 MACT regulations, and the commission did not use that as a basis for the new PBR. Based on technical experience for rich-burn engines less than 500 hp, controls are most likely not needed to demonstrate compliance with the one-hour NO_2 NAAQS; therefore, the commission removed the control requirements for rich-burn engines less than 500 hp. Based on the commission's knowledge of catalyst controls for engines, there is little incremental cost increase for the increased use of catalyst to meet the lower emission rates due to the limited life of catalyst with respect to engine life; the phase-in times in the new rules should be achievable through the replacement of catalyst as part of regular maintenance. Furthermore, the commission is comfortable with removing the control requirements for rich-burn engines less than 500 hp because companies still have to demonstrate compliance with the NO_2 NAAQS and demonstrate emissions are protective according to subsection (k). The commission considered the request to incorporate by reference the specific federal rule citations in the new OGS rules.

The commission has decided to not incorporate the specific federal rule citations because the new OGS rules already include citations indicating that OGS must meet the requirements of all other state and federal rules. The commission prefers to include references to federal rules rather than specifically naming each federal standard because the OGS rules do not have to be updated every time the EPA promulgates new standards or removes an existing standard, which allows the commission to allocate staff to permit reviews to ensure economic development and ensure public health and welfare. The commission has made the new OGS rules consistent with federal rule testing, management practices, and recordkeeping wherever possible to reduce duplicative recordkeeping, testing, and monitoring efforts to minimize cost to industry while ensuring that the same environmental standards are maintained. For engines, the only inconsistency with the federal rules was the additional quarterly testing requirement, has been changed to semi-annual testing as discussed elsewhere. BACT requirements are different from the requirements in 40 CFR Part 60 NSPS and 40 CFR Part 63 MACT, but BACT is not required to be included in the new PBR.

Cirrus commented that the "engine standards in Table 9 of the proposed PBR and Standard Permit are based on engine manufacture date. If an engine is modified, reconstructed, or relocated does it change the "manufacture date" such that the engine becomes subject to a tighter standard?"

The commission has not changed the rule based on this comment. Relocation does

not change the manufacturer or remanufacturer date of an engine. Based on federal 40 CFR Part 60 NSPS rules, if more than 50 percent of the capital cost of a unit, such as an engine, is spent modifying or remanufacturing that unit (i.e. a facility), then that unit is considered a remanufactured unit under 40 CFR Part 60 NSPS rules and is subject to the applicable federal rules accordingly.

Cirrus stated that Table 6 (proposed as Table 9) "(Engine and Turbine Emission and Operational Standards) in both the PBR and Standard Permit does not provide standards for all possible engine manufacture dates. For rich-burn engines greater than or equal to 100 HP, standards are presented for engines that are manufactured either before January 1, 2011 or after January 1, 2011 but not ON January 1, 2011. The same problem exists for lean-burn engines manufactured on June 18, 1992."

The commission has clarified the language in subsection (m), Table 6 in response to this comment.

ETC commented that the engine testing requirements proposed in the new rule are burdensome and go beyond the requirements that should be included in a PBR. ETC stated that the proposed rule requires biennial engine testing for NO_X, CO, and H_2CO (formaldehyde) via three 1-hr test runs. Currently, engines under the existing §106.512 rule require biennial tests for only NO_X and CO via three 30 minute test runs. ETC currently operates approximately 550 active engines in Texas that require stack testing. Currently, three 30-minute test runs for only NO_X and CO costs $2,000. Assuming that biennial testing is performed on 50 percent of the fleet per year, the annual cost is $550,000 under the rules in the existing §106.512. If three one-hour test runs for NO_X, CO, and formaldehyde cost $5,000. Assuming half the fleet is tested in a year, the annual cost is $1,375,000. The proposed engine testing requirements would increase ETC testing costs by approximately 250 percent. The proposed rule also requires quarterly tests for all engines. Quarterly tests for all 550 ETC units would require the addition of three emission technicians. ETC stated that this would result in increased overhead costs of approximately $240,000 per year. ETC further commented that with the implementation of EPA's recently adopted rules for existing engines, nearly all engines will be subject to the new federal testing requirements. As stated earlier in these comments, TCEQ should not impose testing requirements on engines that are duplicative and inconsistent. In lieu of these overly prescriptive and very expensive proposed engine testing requirements, ETC believes that a Preventative Maintenance (PM) schedule, combined with the federal testing requirements, can ensure efficient and reliable engine operation. Typical oil and gas industry engine PM schedules include: (i) Top-end overhaul occurs approximately every 2.5 years, (ii) Complete engine overhauls (engine swings) occur approximately every 5 years. As per §106.512, each PM activity is followed by an emission test via portable analyzer.

The commission has changed the rule in response to this comment. Periodic monitoring is only required for sources subject to Title V Operating Permits for which it is a federally required permit condition. Additionally, the commission decided not keep the EPA reference method testing requirements in the current §106.512 in the new PBR. The commission has aligned the PBR with any testing required by federal rules to avoid duplicative tests. Based on research of current engines, the commission believes that previous engine tests are sufficient for

initial testing when a new engine is brought on-site if the previous engine test was performed on an engine of the same model, year, and control system. Tests done for a federal rule may also be used to show compliance with the PBR requirements if the requirements are the same. In addition, the commission will allow identical groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. The commission has removed the formaldehyde testing requirement from the rule and changed the test run duration to match the period of the EPA test method. Advancements in engine technology and efficiency over the last 25 years have led to new engines with much lower emission rates. In addition, the 40 CFR Part 60 NSPS Subparts IIII and JJJJ and 40 CFR 63 MACT ZZZZ require testing and establish more stringent emission limits for VOCs, NO_X, CO, and formaldehyde than the previous §106.512. Therefore, the commission believes that the new PBR rules will achieve the same emission standards while reducing duplicative testing requirements. This change represents a savings of thousands of dollars a year for each engine, which will allow companies to focus their resources on upgrading or replacing older, more inefficient engines to reduce emissions.

One individual asked if there a testing frequency guide available to satisfy the environmental impact concerns and still be fiscally responsible to the industry.

The commission has changed the rule in response to various comments on reasonable, but necessary, testing for engines to ensure public health and welfare

while minimizing the economic impact on oil and gas companies to allow companies to focus their resources on upgrading older, higher emitting engines.

TXOGA, Anadarko, Noble, ExxonMobil, and GPA commented that, "Any compressor or heated vessel operating at an OGS will have nitrogen oxides and other combustion-related emissions. Thus, based on the generally simple production operations at a typical OGS and as explained in more detail in these comments, a PBR or standard permit is the appropriate mechanism to authorize air emissions at an OGS. TXOGA contends, however, that these relatively simple operations do not merit the degree of regulation that would result from the Proposed Rules. In fact, as OGS are comprised of a series of fugitive emission sources and are subject to federal New Source Performance Standards ("40 CFR Part 60 NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPs") just as other similar fugitive emission sources are under the TCEQ rules, TXOGA questions the need to subject OGS to more stringent requirements at this time. It is TXOGA's understanding that the federal NSPS and NESHAPs, are currently under review by EPA and are likely to be revised soon to impose more stringent requirements on OGS. TCEQ should wait to see what changes will be made at the federal level so that potentially inconsistent requirements are not imposed at the state level that will place Texas operators at an economic disadvantage relative to similar operations in other states."

The commission revised §106.352(j) in response to the commenter's concern about duplicative requirements to include the following: Other requirements, including but not limited to, federal recordkeeping or testing requirements, can be used to demonstrate compliance if the other requirements are at least as stringent

as the associated requirements in the table below." The commission did not change rule language in direct response to the remainder of this comment because the commission believes that there is not necessarily a correlation between simplicity and magnitude of emissions, impacts, etc. The regulatory need for updating §106.352 is different than what the US EPA must consider when promulgating 40 CFR Part 60 NSPS or 40 CFR Part 61, 40 CFR Part 63 NESHAP rules. The proposed PBR will allow duplicate requirements done to comply with a federal rule to also be used for state purposes which will minimize any additional cost to industry. The new OGS rules are consistent with federal rules testing, management practices, and recordkeeping where possible. For the new OGS standard permit, BACT requirements must be met. The requirements for BACT are not the same as 40 CFR Part 60 NSPS and 40 CFR Part 63 MACT. Some of the federal rules and proposed federal rules apply to only very new sources (that is, facilities). The TCEQ is obligated to examine all facilities when proposing a PBR rule. The TCEQ attempted to allow any federal requirements to be acceptable for the proposed PBR. The TCEQ is obligated to examine BACT for all facilities when adopting a standard permit rule, but not for a PBR.

EDF stated that, "This provision should be revised to read: "all seals and gaskets in VOC or H_2S service shall be installed, regularly checked, and properly maintained to prevent leaking."

The commission agrees with the comment and believes it is an obvious best management practice to physically inspect equipment regularly for obvious

problems. Leaks represent lost revenue and have potential negative impacts on off-site receptors. The rule is adjusted to clarify quarterly physical inspection is required.

EDF commented that the fugitive requirements be revised to read: "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 according to the schedule for repair set forth in section (7)(D)."

The commission partially revised the requirement in response to the comment. The requirement refers to "components found to be emitting VOC in excess of 10,000 ppmv leak definition using EPA Method 21, found by visual inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) or found leaking using the Alternative Work Practice in 40 CFR §60.18(g) - (i) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified" which can refer to any leaking component whether it is damaged or not. Components may leak because temperature and pressure changes can cause components to loosen or wear out over time.

TIPRO commented that, "The AVO inspection frequency proposed in §106.352 (e)(7)(A) contradicts what is proposed on Table 8 and should be clarified and made consistent."

Pioneer commented that the proposed fugitive requirements "are in direct conflict with Table 8, Site LDAR Program (G) which states, "AVO 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." Encana commented on §106.352 (e) and Standard Permit Table 8, §106.352(e)(7)(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. Encana Response: The proposed frequencies are potentially conflicting and could cause confusion."

The commission has revised the BMP, and where fugitive monitoring is necessary, the frequency can match the credit needed for compliance. For new facilities, a simple quarterly physical inspection is being required.

Shell supports using the "provisions of 40 CFR Part 63, SUBPART HH, OIL AND NATURAL GAS PRODUCTION 40 CFR Part 63 MACT STANDARD, which includes exemptions from fugitive control of ancillary equipment and compressors where production is <10 percent wt VHAPS. SWEPI proposes that sites using 40 CFR Part 63, Subpart HH should be able to exempt their equipment/piping/compressors from fugitive control when the equipment/piping/compressors contain less than 10 percent by weight VHAPS."

The commission did not change the rule in response to this comment. The proposal is not in accordance with TCEQ fugitive guidance.

A recent study showed that fugitive emissions in the Barnett Shale region alone were estimated at 26 tons per day of VOCs, with 18 tons per day inside the Dallas-Fort Worth metro area. At a minimum, OGS in the Dallas-Fort Worth nonattainment area should be required to conduct more routine inspections—monthly at a minimum—and repair leaks within 3 days. At the very least, the PBR should require repair within 15 days, consistent with the proposed standard permit."

The commission believes companies want to and will be responsive to large leaks because it directly affects their revenue. The more routine seeps and drips are expected and reasonable scheduling of limited maintenance and repair professionals is appropriate. The standard fugitive calculation methods account for emissions from leaking components. The commission has revised the rule to become effective on April 1, 2011 for new sites constructed in the Barnett Shale, including Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Stephens, Somervell, Tarrant, and Wise Counties. New sites located in the rest of Texas would become subject to the requirements on January 5, 2012.

TIPRO and Encana commented that the "TCEQ should consider that operators commonly lease equipment, especially compressors, and that contractual agreements may not allow the operators to repair or replace equipment or components at will. TIPRO recommended that the TCEQ further considers the general implications of the proposed rule changes concerning contracted equipment."

The TCEQ is revising the requirements with respect to instrument fugitive monitoring requirements for the PBR and placing the requirements in subsection (m), Table 9 to be applicable only when necessary for meeting emission limitations. Particular sites at which contractual obligations would inhibit the repair of the leaking equipment in accordance with this rule authorization, will need to be addressed in case by case permitting. As noted above the commission is not mandating the use of instruments for LDAR. Where a company is applying an instrument LDAR program to dramatically reduce emissions the week walk through is required and accounts for the overall 30 percent reduction in emissions from components that are not instrument monitored.

Old Town Neighborhood Association stated "in all phases of oil and gas production facilities should have best available emission control mandates as well as more frequent inspections and maintenance."

The commission agrees with this comment and believes the BMP standards written in the rule ensure that facilities are meeting authorization limits and equipment is kept in good working order.

TIPRO comments that "operators routinely fix leaks they find using audio, visual or olfactory inspection as part of their normal job duties. Additionally, leaks create potential safety hazards for the operator on location. There is no environmental benefit by requiring operators to record their walk-through unless a leak is found. As a BMP, operators conduct several inspections on a regular basis for different purposes (safety, maintenance, etc.) or compliance with other regulatory agencies requirements. As long as the operator ensure that fugitive components in the gas service are included in the most appropriate of these inspections, an equivalency with the AVO method can be claimed."

Encana commented on Table 8 PBR §106.352 and Standard Permit- Category - Site LDAR Program - (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 Encana Response: Operators fix leaks they find using audio, visual or olfactory inspections, Operators fix these leaks as part of their job duties because leaks are a loss of product and therefore a loss of revenue. Additionally, leaks create potential safety hazards for the operator on location. There is no additional environmental benefit by requiring operators to record their walk-through unless a leak is found. A requirement to record a walk-through where no leaks are found only provides additional enforcement risk to operators over recordkeeping, The requirement to record a weekly walk-through should be stricken from the proposed regulation and recordkeeping should only involve leaking components."

The TCEQ is revising the requirements with respect to instrument fugitive monitoring requirements for the PBR and placing the requirements in subsection (m), Table 9 to be applicable only when desired by a company to certify lower

emission potential or when necessary and elected for meeting emission limitations. The new BMP language maintains a physical inspection quarterly with the simple check box kind of record with notes of leakers as suggested. When a company chooses the more extensive LDAR program for emission reductions, the weekly check on components is required. The commission believes operators can be and generally are attentive and responsive to leaks because leaks represent lost revenue.

TPA commented that subsection (e)(6) "relating to fugitives needs to be clarified. The applicability of this provision is uncertain. It is not clear if this subsection is designed to apply to all existing fugitives or to new fugitive components as was expressly stated by the original drafters of this subsection in (e)(7)."

The commission is revising the BMP with respect to fugitive components and emissions to make it dramatically simpler and less costly and clearer. The BMP applies to all fugitive components at a site, but does not require any instrument monitoring. The operator must know the components on site to estimate the uncontrolled emissions. The commission is now only requiring that the operator take a look once quarter to make sure the components are not obviously leaking. The commission wants to encourage any company that wants to use an instrument monitoring program at a site to dramatically reduce the fugitive emission potential. If a company elects to use the instrument monitoring to take credit for the emission reductions, to meet emission limitations or certify lower emissions,

they will need to comply with the monitoring requirements as prescribed in subsection (e)(7) and Subsection (m), Table 9 with demonstrations and records in subsection (m), Tables 7 and 8.

Senator Davis commented that, "To protect the public, leaking components should be repaired or replaced within 7 to 10 days, depending on parts availability."

Representative Burnam proposes that leaking components be repaired within 72 hours after a leak is found at a manned site and 15 days at an unmanned site except under extenuating circumstances.

The commission has not changed the rule in response to this comment. In Chemical Plants and Refineries with a significant number of components and trained maintenance staff that work around the clock, the commission expects that the repair or replacement can be reasonably accomplished in 15-days. However, resources and equipment are not as readily available at OGS, and additional time is appropriate for the typical seeping or dripping component. Where feasible, companies are presumed to repair leaks as quickly as possible, especially large leaks, because they are losing product.

One individual commented that the only significant source of VOC's that may not be addressed is from pneumatic controllers and pneumatic pumps and provided calculation worksheets used to assess these emissions. "Most oil and gas facilities have many chemical pumps, at least one on every chemical tank that operates 24/7. Some of these pneumatic pumps (Wilden and Yamada) emit significant VOC's when operated frequently to move fluids. The individual typically conducts a count of all controllers at a facility and accounts for them under one EPN (PC1). The same for chemical pumps. Pneumatic fluid pumps are calculated separately. These pumps have an emissions stack/port, and should not be considered fugitive. I don't want any more regulation than we have, but I want this latest revision to be comprehensive."

EPA Region 6 questioned whether the TCEQ has "considered eliminating natural gas-actuated pneumatic devices by requiring the replacement with the installation of low- or no-bleed pneumatic devices at all new facilities and along all new transmission lines, retrofitting or replacement of existing highbleed pneumatic devices with low- or no-bleed pneumatic devices, require the use of pressurized instrument air as the pneumatic fluid instead of natural gas, or ensure that all natural gas actuated devices discharge into sales lines or closed loops, instead of venting to the atmosphere."

The commission has not made a change based on this comment. The technology had not been evaluated in sufficient detail, would expand the scope of the rule and cannot be added in this rulemaking. The commission has historically treated these emissions as fugitive emissions and will continue this practice since these emissions are not normally large in amount. The commission expects that computer programs, manufacturer's emissions factors, industry emission factors, ideal gas law, or another appropriate method be used to estimate the emissions.

EDF recommends "the following BMP: Installation of BASO Valves on All Gas-fired Heaters. Crude oil heater-treaters, gas dehydrators and gas heaters located at exploration and development sites have pilot flames which can be extinguished by strong winds, causing the venting of natural gas. BASO valves automatically shut off the flow of natural gas upon the extinguishment of the pilot flame, thereby preventing unnecessary pollutant and methane losses. BASO valves are operated by a thermocouple that senses the pilot flame temperature and do not require electricity or manual operation. They are therefore ideal for remote locations. Capital costs are negligible, with each valve costing less than $100, and savings can be as great as 203 Mcf year for a 1,000 barrel per day heater-treater that experiences a flameout period of 10 days annually. Payback depends on how often the pilot flames go out and for what length of time. Typically payback occurs in less than 1 year. A clean air standard based on the installation of BASO valves could result in significant product savings and emission reductions."

The commission appreciates the information and will look into sharing the information in the Pollution Prevention outreach programs. The technology had not been evaluated by the TCEQ in sufficient detail, would expand the scope of the rule and cannot be added in this rulemaking. The fugitive monitoring requires leaks which are observed from the compressor to be repaired or replaced. The commission plans to research this information further for inclusion in a future update to this rule. The commission also would like to clarify that the situation where the pilot flame is extinguished by a strong wind represents an unauthorized emission, commonly called an upset, which would need to be reported under 30 TAC Chapter 101.

EDF recommends "the following BMP: Replacing Compressor Rod Packing From Reciprocating Compressors. Reciprocating compressors are one of the largest sources of methane emissions at natural gas compressor stations. Methane emissions are produced by leaks in the piston rod packing systems used in the compressors—especially from older systems. Replacing compressor rod systems reduces methane emissions, increases savings, and results in greater operational efficiencies and equipment life-spans. Average gas savings equal $6,055 a year and far exceed the $540 implementation cost and the payback is 2 months. This, along with other strategies such as improving operating practices when compressors are taken off-line and replacing old flanges and fittings along pipeline, are expected to yield 0.9 MMT CO_2 annually and save the oil and gas industry $17 million in annualized net savings."

EDF recommends "the following BMP: Replacement of Wet Seals with Dry Seals on Wet Seal Centrifugal Compressors. Centrifugal compressors are widely used throughout the natural gas production and transmission sectors. Seals on rotating shafts are used to prevent natural gas losses from compressor casing. Many of these seals use high-pressure oil as a barrier against escaping gas. These types of seals, referred to as "wet" seals, produce methane emissions when the circulating oil is stripped of the gas it absorbs. Dry seals use high-pressure natural gas instead of oil to prevent gas losses. They also have lower power requirements, improve compressor and pipeline operating efficiency and performance, enhance compressor reliability, and require significantly less maintenance. A dry seal can save about $315,000 per year and pay for itself in as little as 11 months. One Natural Gas STAR partner who installed a dry seal on an existing compressor reduced emissions by 97 percent, from 75 to 2 Mcf per day, saving almost $187,000 per year in gas alone. "

EDF recommends "the following BMP: Leak Detection and Repair at Compressor Stations in the Transmission and Storage Sectors. Compressor stations occur throughout the natural gas transmission and storage sectors and act to compress the gas to varying pressure points to overcome pressure losses that occur along a long-distance pipeline. According to EPA, compressor stations in the transmission sector alone account for approximately 50.7 Bcf of methane emissions annually. A leak detection and repair program, similar to that already required for equipment and compressors located at natural gas processing plants, see 40 CFR Part 60, Subpart KKK, offers a cost-effective way to prevent and eliminate emissions from compressor stations. Baseline surveys done by EPA partners have revealed that the majority of leaks come from a small number of parts, mostly valves, and that once these parts are identified, cost-effective repairs can be streamlined to accomplish maximum emissions reductions and gas savings."

The commission appreciates the information and will look into sharing the information in our Pollution Prevention outreach programs. The technology had not been evaluated by the TCEQ in sufficient detail, would expand the scope of the proposed rule and cannot be added in this rulemaking. The proposed fugitive monitoring would require leaks which are observed from the compressor to be repaired or replaced.

HCPHES "is supportive of the proposed Permit by Rule and Standard Permit changes as they address some of the issues Harris County has witnessed and documented at oil and gas facilities. Specifically, Harris County has visual Gas FindIR confirmation and documentation that OGS facilities have uncontrolled emissions from points specifically addressed in the proposals."

The commission has changed the BMP to only require a quarterly physical inspection. Instrument monitoring requirements are reserved for sites where monitoring reduction credit is necessary to meet the emission limitations. The use of an infrared camera is an option not a requirement. The commission encourages sites to use the incentive program in Chapter 101. The commission is revising the requirements with respect to instrument fugitive monitoring requirements for the PBR and placing the requirements in subsection (m), Table 9 to be applicable only when a company chooses to certify emissions to a level below the maximum potential to emit, or when it is necessary to limit the maximum potential to emit to meet the emission limitations. Where additional monitoring is necessary to meet the emission limitations, the enhanced monitoring will be applicable to all fugitive components associated with the registration for impact purposes within the quarter mile impact evaluation area. The BMP applies to simple quarterly physical inspections. All components are expected to be kept in good working order as designed.

The commission has revised the LDAR requirements of the PBR to only be required when necessary for meeting emission limitations. Sites where an LDAR program is not necessary to meet the emission limitations will be required to physically inspect all components quarterly. The commission believes companies do this as a practical matter even more frequently, but the requirement provides a

baseline environmental spot check, which will address large leaks. As suggested the commission is requiring all operators, who choose to implement an LDAR program, to also inspect fugitive components once a quarter. The protectiveness evaluation is site-wide, which will require an accurate component count. Then, if the company wants, or needs to use an instrument aided LDAR program to establish dramatically lower emission potential, the company may use a standard prescribed approach as noted in the adopted subsection (m), Table 9. Table 9 also allows the optical imaging approach to gain reductions as noted.

SWEPI commented that their experience in using the "camera over a wide range of conditions, and verified with bagging or high flow sampler type measurements, shows that 0.004 lbs/hr leak detection is a reasonable threshold for location gas processing (natural gas and condensates) at operating temperatures. This would support less frequent monitoring. Emissions reductions would also be achieved relative to Method 21 by inclusion of difficult to monitor components."

The commission is revising the instrument fugitive monitoring requirements for the PBR and placing the requirements in subsection (m), Table 9 to be applicable only when necessary for meeting emission limitations. The requirements are adjusted to allow the alternative work practice in lieu of EPA Method 21.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "The leak definition given in §106.352(e)(7)(B) is 10,000 ppm. References to other values should be removed."

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Method 21 monitoring at all sites is unnecessarily burdensome. Also, this reference contradicts the requirement given in §106.352(e)(7)(A), i.e. annual testing."

The commission has only required the LDAR programs with instrument monitoring when they are necessary to meet emission limitations. There are several approaches available that apply different leak definitions depending on the program selected. The site may use the leak definition necessary to meet the emission limitation.

Encana commented on Table 8 PBR §106.352 and Standard Permit - Category -- Site LDAR Program - (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. Encana stated this requirement is not clear. If the requirement is to monitor weekly until repaired, this is impractical to implement for operators with hundreds of locations, many of them remote, there is no environmental benefit to monitoring for the leak over simply assuming the component leaks until repaired. This is an unnecessary and costly requirement with no additional benefit and should be stricken from the proposed rules."

The commission is revising the requirements with respect to instrument fugitive monitoring requirements for the PBR and placing the requirements in subsection

(m), Table 9 to be applicable only when desired by a company to certify lower emission potential or when necessary and elected for meeting emission limitations. Where a company elects to apply an instrument monitoring LDAR program minimally capping of all open ended lines is required to eliminate the leak potential. The 72-hour check is associated with open ended lines created during maintenance activities, the majority of which are expected to be returned to normal in a few hours. In the rare cases where the activity will leave an open ended line in place for more than 72 hours the company should either cap it or monitor it to be sure it is not leaking. The language for the PBR has been adjusted to allow that check to cover up to a 45-day turnaround (not expected at an OGS) or conduct 30 rechecks. Based on representations from companies the need to monitor open-ended lines for extended maintenance periods at OGS should be extremely rare.

Encana commented on Table 7 - Fugitive component monitoring and repair program or LDAR. "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 . . .. 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, §30.18(g) - (i). Encana Response: Encana agrees that response factors are important to ensure proper demonstration of compliance with Subpart KKK, However, it appears that many of the proposal LDAR testing requirements are BMPs, It is unrealistic to believe mechanics and roustabout crews will understand and know when to apply which VOC response factor. Encana recommends that the requirement to consider response factors be removed from the proposed rules."

SWEPI commented on the LDAR "For OGS, TCEQ Alternative Work Practice (AWP) should be an option in lieu of Method 21, not in addition to Method 21, as is required in 30 TAC Chapter 115 and EPA AWP. For OGS a requirement to use method 21 as part of the AWP is redundant and offers no value in terms of added emissions reductions. The AWP emissions reduction model was based on refineries where there is a high component density and low leak thresholds. The mass of emission reductions and required repairs with Method 21 would generally be significantly less than already permitted emissions from natural gas supplied instrument control emissions. These are production sites, mostly in rural areas, and mostly in ozone attainment areas."

The commission is revising the instrument fugitive monitoring requirements for the PBR and placing the requirements in subsection (m), Table 9 to be applicable only when necessary for meeting emission limitations. The requirements are adjusted to allow the alternative work practice in lieu of Method 21.

Shell considers the "voluntary Texas AWP (TAC Title 30 Part 1 101.153) using Smart LDAR as a reasonable option for monitoring. Consideration should be given to the fact that the Texas Voluntary AWP was adopted just recently for the purpose of encouraging the use of optical gas imaging and establishing incentives for its use. Significant emissions reductions can be achieved with the AWP and the initial investment in cost and training using an IR Camera will encourage use by operators and environmental staff for safety and MSS activities. For owner/operators who volunteer for inclusion in the AWP, there should be no requirements to use traditional portable analyzers associated with Method 21 and verification of repair should be permitted with the IR camera. However, 2 years of video recordkeeping requirements should be used instead of the proposed 5 year storage requirement to reduce the information storage burden while providing adequate retention period for any internal or agency review. Although this frequency may be less stringent for a state program than the Federal AWP, the 2 year retention period is a valid and reasonable records retention allowance since the program is voluntary."

The commission is not mandating the use of instruments for LDAR as BMP, only when emission reduction is necessary to meet emission limitations. If this results in more oil and gas companies volunteering for the AWP that would be an excellent out come. The 5-year retention for the AWP is part of that rule and not within the scope of this analysis.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated that, "The fugitive monitoring program described is entirely too cumbersome and costly for remote oil and gas facilities. Remove this requirement. Alternatively, revise to "A) A monitoring program plan must be maintained that contains, at a minimum, the following information: (i) The job position of the person performing the monthly AVO observation. (ii) Designation of where the records will be maintained for AVO observations. (i) an accounting of all the fugitive components by type and service at the site with the total uncontrolled fugitive potential to emit estimate; (ii) identification of the components at the site that are required to be monitored with an instrument or are exempt with the justification, note the following can be used for this purpose:

(a) piping and instrumentation diagram (PID); or (b) a written or electronic database.; (iii) the monitoring schedule for each component at the site with difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), identified and justified, note if an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times and a record of the plan to monitor shall be maintained; and (iv) the monitoring method that will be used (audio, visual, or olfactory means; Method 21; the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (v) for components where instrument monitoring is used, information clarifying the adequacy of the instrument response; (vi) the plan for hydraulic or pressure testing or instrument monitoring new and reworked components.""

Encana commented on Table 8 PBR §106.352 and Standard Permit - Category - Site LDAR Program - (A) (I) "an accounting- of all the fugitive components by type and service at the site with the total uncontrolled fugitive potential to emit estimate; Encana Response: Actual counts of all fugitive components are extremely difficult and burdensome on operators, This requirement should be reserved for larger facilities and engineering estimates should be allowed for the smaller facilities. Encana asserts this requirement should only be required for facilities that emit greater than 80 percent of Part 70 Major Source thresholds."

The commission has changed the rule in response to this and other comments. The PBR requires as a result, only a quarterly physical inspection for leaks which must be repaired. All other LDAR or monitoring requirements are voluntary and applicable only if chosen for credit by the operator.

Encana commented on Table 8 PBR §106.352 and Standard Permit- Category-Site LDAR Program - (A)(ii) "identification of the components at the site that are required to be monitored with an instrument. Encana Response: Encana asserts this requirement should only be required for facilities that emit greater than 70 percent of Part 70 Major Source thresholds. Additionally, requiring an LDAR program for potentially only small portions of a facility would be too difficult to manage."

The commission is revising the requirements with respect to instrument fugitive monitoring requirements for the PBR and placing the requirements in subsection (m), Table 9 to be applicable only when desired by a company to certify lower emission potential or when necessary and elected for meeting emission limitations. Application of this new rule only occurs where companies modify or add new facilities in accordance with state regulations.

TPA argued that "Another major flaw in the PBR is that it would prescribe a host of detailed control and operating requirements. TPA believes that such prescriptive requirements are unnecessary and have no place in a PBR. If a site meets the overall emissions limits requirements set forth in the PBR, then that is all that should matter; the particular means by which the site is able to meet those limits is irrelevant to the environment and it should be irrelevant to the TCEQ. The inclusion in the PBR of numerous pages of detailed control requirements would inject unnecessary confusion and complication and would make it harder for the regulated community to determine whether or not a PBR could be claimed."

The commission has changed and clarified the rule to emphasize that control systems are optional and chosen by the operators to rely upon as needed. If a control is used to reduce emissions, the commission has determined it is essential that these systems are designed, operated, monitored, and records kept which demonstrate the reductions are actually achieved.

ConocoPhillips suggested "the following issues related to BMPs and other standards: a) There should be no duplicate standards for facilities where federal standards exist, e.g, engines. b) TCEQ should allow for a 180 period between the publication of the final rule and the effective date so that oil and gas industry can plan for successful implementation of the rule."

The commission has changed the rule in various subsections and agrees portions of this comment. The commission has included language to allow for the use of existing records or use records for federal requirements and not require duplicative documentation. The commission has postponed the effective date for new projects until April 1, 2011.

ETC commented that the "PBR would prescribe paint color requirements for storage tanks and process vessels. This is an overly prescriptive and unnecessary requirement. As previously stated in these comments, if emissions at a site are being controlled to protective levels, through whatever means, additional control should not be required, At most, any tank color requirement that remains in the PBR should be moved to subsection (e) dealing with BMPs, and should be optional. Another problem with (f)(1) is that the subsection, as currently written, would apply to all tanks, even tanks with minimal throughput or that contain only water. Notwithstanding the fact that the tank paint requirement should be removed from the PBR, this provision should be rewritten to clearly state that it does not apply if the tank throughput is less than a *de minimis* threshold, or if the tank contents contain <10 percent by volume VOC. (f)(1)(C): The color requirement does not apply to tanks in transmission service. (f)(1)(D): The color requirement does not apply to tanks with true vapor pressure of compound at storage conditions >1.5 psia."

TPA commented on Subsection (f)(1)"Tank color requirements. This subsection would prescribe paint color requirements for storage tanks and process vessels. This is an unnecessary requirement. As stated elsewhere in these comments, if emissions at a site are being controlled to acceptable levels, through whatever means, then there is no reason why the additional control of a prescribed paint color should be imposed on operators. At most, any tank-color requirement that remains in the PBR should be moved to subsection (e) dealing with BMPs."

TPA stated that, "Another problem with the subsection, as currently written, would apply to all tanks, even tanks with minimal throughput or that contain water only. If the paint-color requirement is kept in the PBR, then it at least should be rewritten to make clear that it does not apply if the tank does not meet a specified *de minimis* throughput level, or if the tank contains < 10 percent by volume VOC, or if the tank emissions are less than 1 tpy. (f)(1)(C): "The color requirement does not apply to tanks in transmission service."; (f)(1)(D): "The color requirement does not apply to tanks with true vapor pressure of compound at storage conditions < 1.5 psia."; and (f)(1)(E): "The color requirement does not apply to tanks with emissions that are less than 1 tpy.""

Encana commented that, "This "painting" requirement appears to include storage tanks, process vessels, and temporary liquid storage tanks indistinctively. Encana recommends that this provision be revised to exempt vessels with a diminims (sic *de minimis*) throughput level or tanks containing < 10 percent by volume VOC."

Fasken "has seen the cost estimates provided by the Permian Basin Petroleum Association to install smokeless combustors on flares, purchase and operate vapor recovery units, and paint tank batteries in reflective colors. Fasken believes the potential costs associated with these proposals would be an economic hardship for many independent operators. Fasken disagrees with TCEQ's analysis that there would be no significant economic effect and states that TCEQ needs to perform an economic analysis as required by THSC, §2001.0225. Fasken is concerned about the immediacy of the implementation of these regulations and that all operators will be scrambling to purchase equipment and get facilities into compliance, adding to the economic hardship. Fasken believes that the heart of the proposal is dramatically lowered standards for VOCs, H_2S, and SO_2. No other gas producing state has limits this low. Fasken proposes that the regulation be withdrawn and a new coordinated effort between TCEQ and the industry begun. Input from the oil and gas community is critical to balanced regulation. "

Devon commented that, "The proposed PBR requires that "tanks and vessels" shall be of a color that minimizes the effects of solar heating (including but not limited to white or aluminum). It also requires that a VRU be installed on a new or modified tank that cannot be painted white or other reflective color. Devon recommends that the term "vessels" be modified to read "atmospheric storage vessels" such that it is clear that the solar absorbance (sic absorptance) requirements do NOT apply to pressure vessels or enclosed process, non-emitting equipment where paint color has no direct impact on emissions. Additionally, it is not technically feasible to require the installation of a VRU based on tank color and should be removed from the (f)(1) citation. The successful operation of a VRU depends on many factors, including an adequate vapor rate and a low pressure delivery point at the site, which is unrelated to the color of a tank. Finally, it is strongly recommended that a VOC emission threshold be applied to the working and standing emissions estimation, such as 5 tpy, so there is a technical basis supporting this costly requirement."

ConocoPhillips is "requesting that the requirement that tanks need to be painted with a reflective color in order to minimize emissions not apply to fiberglass tanks and to tanks with actual emissions less than 1 tpy. If the emissions from a tank are 1 tpy or less, the additional reductions by painting a tank a different color will be a fraction of a ton, thereby reducing the cost effectiveness of this type of control."

The commission has changed the rule. Tank paint color is not a requirement, however the commission highly encourages companies to consider low absorptancy colored paint when the tank is initially painted or repainted to minimize the financial cost. A paint color with a low solar absorptance can reduce the amount of emissions from process vessels and can be of great financial savings to producers. This control is not mandated by this rule, the requirements are an

option where paint color is needed to meet the emission limitations of this rule. The color requirements are the minimum acceptable reflective standard if control is deemed necessary. Furthermore, the companies may choose to use any tank color that can reasonably meet the 0.43 solar absorptance factor reference in AP-42. This solar absorptance factor includes the color tan, used to reduce unsightliness since it is a "landscape-neutral color."

SWEPI commented that, "It is proposed that all tanks are painted white to ensure that solar absorbance of the tanks is 0.43 or less. Although painting a grey tank white may impact bulk liquid temperatures to some extent and emissions may be slightly lowered, this is a process and asset function and not an emission source subject to rule. In addition, allowing black to minimize vapor entrainment in a design is valid. Nevertheless, using the relative solar absorbance of a light grey versus white tank (from API 19.1 Standard) and calculating the relative bulk temperature difference from the API 19.1, 4th edition, only approximately 2.2 degrees F difference is generated between white and light grey painted tanks. An alternative consideration should be given to paint only the fixed roof with a white overcoat and allowing the sides remain original."

TIPRO commented that, "Some production facilities use one tank for both oil and water storage and rely on the dark color to facilitate separation. TCEQ uses "condense" when the proper word in this context appears to be "liberate." The commission should clarify the rule so that tanks can be painted black when used as part of the separation process and how this is claimed and documented. TIPRO further comments that this requirement is overly prescriptive, and the cost benefit does not add up."

Tank paint color of a low solar absorptance is optional and tanks or vessels purposefully darkened to facilitate the separation process are exempt from color requirements. Dark color could be useful in heavy high wax content crudes and to aid the rate of oil water separation when that is a purpose of the tank. Tank paint color standards for solar absorptance were referenced from Table 7.1-6 in Compilation of Air Pollutant Emission Factors (AP-42). While the temperature difference associated with the difference between white and light gray paint may be small, an increase in temperature will increase emissions. Therefore, the agency feels it is important to set a limit in order to minimize the potential emissions of a site. The commission agrees with the commenter that liberate is a more logical term, but because of revisions to the rule, the term is no longer included.

Akzo Noble asked "how a company may determine if their tank color falls within the boundaries of the 0.43 or less standard? EPA's document referenced in the proposed rule is fairly vague. Tan was listed but I'm curious how the TCEQ will determine if a tan is too dark."

Tank color solar absorptance can be determined by referencing Table 7.1-6 in the Compilation of Air Pollutant Emission Factors (AP-42) document. Additionally, applicants can contact paint providers to determine the rating of paints most applicable to this requirement. The color tan was reference from the AP-42

document mentioned above which has the color listed with a solar absorptance rating of 0.43 in good condition.

Jones Blair Paint recommended "a high gloss tan color to meet the proposed solar radiation absorptance value. They also commented that TCEQ specify a coating system for tanks with the VOC emission rate of 100 grams per liter (g/l). The current VOC limit in Texas for industrial coatings is 350 g/l. "It makes little sense to set a regulation for low emissions of the gas and use a high VOC product to paint the tanks." Recommend a separate rule for those tanks that are painted white only."

The commission has revised the rule to not require a particular paint color. Applicants who choose to follow the optional painting requirements of this rule, painting of the tank will have to meet either PBR §106.263 and/or §106.352 along with any other regulatory requirements such as 30 TAC Chapter 115 and 40 CFR 61, 63 NESHAP.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested clarification on "What constitutes a "record of maintenance of paint color and vessel integrity." Clarify that the color requirement does NOT apply to Process Vessels, but rather Storage Vessels. Non-emitting equipment, such as enclosed pressurized process vessels, should NOT have a solar absorptance specification since there are no direct emissions from these equipment types."

The commission will accept sufficient documentation from either the tank manufacturer or paint producer establishing that the vessel was manufactured according to intended design. Additionally, the documentation should demonstrate that the paint applied to the vessel meets the appropriate solar resistant requirement. For existing vessels, a recorded visual inspection of tank integrity and conditions will satisfy recordkeeping requirements. This documentation is only required when a company chooses to paint a tank to meet emission limitations.

Jones-Blair Paint Company (JBP) commented "1) As a part of the rule 2010-018-106-PR, set the coatings VOC limit for all petroleum AST's in the state at 2.8 lbs/gallon, 330 grams/liter. (The present AIM Industrial Maintenance Coatings limit in Texas is 3.5 lbs/gallon, 420 grams/liter. All tanks would include liquid natural gas, gasoline, diesel and crude oil whether on production sites or bulk storage facilities. This would be a significant reduction of better than 20 percent of hydrocarbon emissions for the coatings alone. This could prove to be enticing to the EPA along with the emission reduction of the fuels in the tanks after coating them with the specified coatings. Proof of concept of the system is available to you as provided by CARB for AST's for gasoline. 2) Consider painting all tanks with Jones-Blair Acrylithane H_2S #45080/99951 aliphatic acrylic urethane high gloss (90 + when measures at 60 degrees) bright white. This could include the natural gas tanks that are now Tan. These coatings are in the 63 percent volume solids range and have superior gloss retention for several years and will not chalk like epoxies or conventional alkyd type coatings. (Chalky or dull paint films will not have the reflectance values that non-chalking high gloss does.) The 2.8 lbs VOC coating systems are currently in place in Texas for ExxonMobil bulk storage gasoline tanks as well as many others.

Should Tan continue to be a consideration for natural gas, the same coating could be used in the 90+ gloss and non-chalking, Jones-Blair Acrylithane H_2S Urethane, item code A2W-xxx/99951 Tan Gloss. 3) In conjunction with #2, it would be advisable to use a 2 inch vent pipe with PV Valve to keep the standing vapors in the tanks. This is similar to what CARB has done with the gasoline storage tanks in CA. (Rule VR-301-A.) Should you need product information on the PV valve, I can send the information on the one specified by CARB as produced by Husky Corporation. The specified coating system along with the PV valve could reduce emissions down to as little as 1 lb per thousand gallons of fuel. That is at least 3 times less than your proposed rule for Tan colored tanks. As far as I know, the current vent cover in Texas is a mushroom type open vent that simply keeps rain out of the tanks and allows the hydrocarbon vapors to escape. Standing loss vapors could mean as many as 5 - 6 lbs of hydrocarbon emissions per 1,000 gallons of fuel. 4) One commenter provided Technical Data Sheets and MSDS for both the Acrylithane H_2S Urethane topcoat white as well as the Ureprime Epoxy Urethane Primer for your perusal."

The commission appreciates the information and will look into sharing the information in the Pollution Prevention outreach programs. The VOC content of coatings appropriate for OGS has not been evaluated by the commission in sufficient detail, would expand the scope of the proposed rule, and cannot be added in this rulemaking.

The City of Fort Worth commented that "ordinances regulating gas drilling in many cities including Fort Worth disallow white and reflective metal tanks and require "neutral colors" for tanks to reduce the potential for visual clutter and to ensure that the facilities do not diminish the aesthetics of the surrounding community. This creates a conflict between the proposed rules and City ordinance." The City of Fort Worth also commented that "more importantly, using paint color is an inefficient emission control technique that by TCEQ's own estimates has a maximum VOC control efficiency of approximately 40 percent. In contrast, control devices on tank stacks and vents such as vapor recovery units, flares, thermal oxidizers, and carbon adsorption units generally have control efficiencies in excess of 95 percent of VOC emissions. Furthermore, paint color does not provide as effective control of flash emissions, which by some accounts are the majority of VOC and HAP emissions from many tanks." The City of Fort Worth also commented that "TCEQ should require control devices on all OGS tanks including those below a 10 tpy threshold due to the density of sites and proximity to densely populated areas in the Barnett Shale region. With respect to major sources in nonattainment areas such as Dallas-Fort Worth, Lowest Achieveable Emission Rate (LAER) is the appropriate control standard and it is not clear if that standard has been used in developing the standard permit requirements aside form reference to other rules that may not, in and of themselves, address all emission units at oil and gas sites."

PBPA commented that, "The requirement that petroleum storage tanks be painted reflective colors will impose substantial financial cost to operators and result in an unsightly visual blight across the landscape where operators could otherwise, at their discretion, paint their tanks more landscape-neutral colors. If such a requirement is to remain in the final rule, it should be keyed to the gravity of the oil stored as tank heating losses are substantially great for condensates than for crude oils."

The commission has revised the rule to not require a particular paint color except when a company chooses to paint a tank to meet emission limitations. Additionally, the oil and gas standard permit may not be used to authorize major sources.

TPA commented that, "The PBR would allow companies to provide contract information to TCEQ in order to demonstrate the existence of prior commitments that would prevent compliance with tank color requirements. Information deemed confidential or sensitive by the providing party may be redacted or submitted under seal."

EDF commented that, "The TCEQ should revise this section to allow for the possibility that an outreach and education campaign to municipalities, homeowners associations, and other parties could result in amendments to existing requirements affecting tank color. Specifically, should the law, ordinance, or contract requiring a color other than white be repealed or otherwise cancelled in the future, then this exception should expire within 6 months of the effective date of such an action, and compliance should be required."

The commission has revised the rule to not require a particular paint color except when a company chooses to paint a tank to meet emission limitations. Since the tank color is optional, the commission has not included a requirement for compliance after a law, ordinance, or contract requiring a color other than white is repealed. The proposed language regarding confidentiality would be declaring, certain information to be held confidential without a legal review indefinitely. The

commission will continue to accept confidentially submitted information by an applicant as currently published in all permit application guidance. If there is an open records request, the commission will coordinate with the Texas Attorney General's Office to determine the confidentiality status of the submitted information in accordance with state laws.

Akzo Noble asked "how "good" and "poor" paint condition would be determined as referenced in EPA Table 7.1-6 PAINT SOLAR ABSORPTANCE FOR FIXED ROOF TANKS?"

The commission believes that the definition of "good" condition in regards to tank color as: Paint shall be applied according to paint producers recommended application requirements if provided and in sufficient quantity as to be considered solar resistant. Paint shall be maintained in and in no way may compromise tank integrity. The agency defines "poor" condition as: Paint that has either not been applied according to paint producers' recommendations or applied in insufficient quantity to be considered affective as solar resistant. Additionally, if the paint is not maintained properly (chips) or compromises tank integrity (holes).

SWEPI commented that, "If a tank is painted grey and is in good condition, allowances should be made to only repaint the tanks white when normal wear would dictate repainting. There are no incentives or credits for repainting existing grey tanks with good paint condition considering the costs associated with painting a complete tank battery may be over $1,000,000, which is well below the PBR cost estimates for tank painting ranging from $6,000 to $20,000. As written, the proposed PBR would require rebuilding an existing asset in good condition with perhaps only marginal benefits obtained at a very high cost. New tanks or tanks with poor paint condition scheduled for a regulatory required mandatory landing and inspection should be painted white, off-white, or aluminum with an initial solar reflectivity index of 0.49 (aged white or beige)."

The commission's tank paint color requirements are optional except when a company chooses to paint a tank to meet emission limitations and only intended for periods when tank initial painting or repainting are required. Therefore, the financial burden associated with tank painting is a necessary cost of operational procedures if needed. Furthermore, the agency has allowed the use of any tank color that can reasonably meet the 0.43 solar absorptance factor reference in AP-42. This solar absorptance factor includes the color tan which has been demonstrated as a color most pleasing as a "landscape-neutral color."

EDF commented that it supports the requirement that "tanks be painted white or other reflective color to reduce emissions, or that a VRU be used. The TCEQ should require existing tanks in the East Texas Region to meet the requirement within 1 year of the start of operation of a new source triggering an OGS PBR authorization at the site."

Tank color is not a requirement, however the commission highly encourages companies to consider low absorptancy colored paint when initial painting or repainting are required.

EDF recommended that for claims of control efficiency above 80 percent, the TCEQ require companies to submit a written justification in addition to the proposed enhanced monitoring and testing."

The commission has reassessed the available data and concurs with industry and EPA positions that support the use of the GRI-GLYCalc program with proper data to estimate the efficiency of an add-on condenser for a glycol reboiler that captures water and BTEX. A company will need to provide the GRI-GLYCalc report, detailed records, and information that will support the actual expected efficiency and emissions. The commission has also updated subsection (e)(8) to specify that all appropriate calculation methods are used consistent with protocols established by state and federal regulators.

Devon commented that "the rule proposal requires that glycol dehydrator condensers may claim up to 80 percent control with "appropriate monitoring" and greater than 80 percent with enhanced monitoring, which includes BTEX condenser stack testing. From Table 8, the rule further explains that continuous temperature monitoring is required to claim 80 percent efficiency, which represents an undue cost burden, particularly for remote unmanned OGS. Devon recommends that weekly manual temperature readings be recorded and records maintained that document the temperature is less than the maximum temperature represented in the GRI-GlYCalc simulation used for permitting, which should be adequate to claim up to 90 percent efficiency. Claims greater than 90 percent would perform the enhanced monitoring, which includes continuous temperature monitoring and stack testing. The proposal allows for 80 percent VRU efficiency with basic monitoring and up to 99 percent efficiency with enhanced monitoring. There appears to be a lack of technical basis for deriving the 80 percent efficiency and Devon maintains that 95% efficiency with basic monitoring is more consistent with other state permitting programs and is more in line with the 30 TAC Chapter 115 nonattainment tank rules (30 TAC §115.112(a)(3)). For tank hatches and openings with proper gaskets and seals, 95 percent capture allows for 5 percent downtime throughout the year."

The commission has reassessed the position and data and concurs with industry and EPA positions that support the use of the GRI-Gly Calc program with proper data to estimate efficiency of an add-on condenser for glycol reboiler that would capture water and BTEX. Proper operation of a glycol dehydrator requires appropriate set up and monitoring. Where add-on control to a flash tank vent and the glycol reboiler vent are not needed only basic unit monitoring is appropriate. Where a company elects to certify or needs to prove lower emissions with add-on controls including a condensor on the reboiler vent, additional control monitoring is required. Relief for the condenser temperature monitor and other parameters is available where all the vents are always controlled with combustion or recovered with a VRU.

SWEPI commented that it is Nordon's opinion that sampling at the exhaust of the combustion is by far the most cost effective and reliable place to sample. If recovery efficiency (condenser) or oxidation efficiency (combustor/heater) is required then more sampling or modeling is necessary."

The commission has reassessed the position and data and concurs with industry and EPA positions that support the use of the GRI-Gly Calc program with proper data to estimate efficiency of an add-on condenser for glycol reboiler that would capture water and BTEX. A company will need to have the detailed record and information that will support the actual expected efficiency and emissions. As suggested sampling of combustion exhaust can be done effectively and only if a company elects to claim enhanced efficiency of a combustion control device is sampling required.

El Paso stated that the "TCEQ should include an exemption for dehydrator still column condensers (sometimes referred to as "BTEX units") where the venting of non-condensable vapor is directed to a combustion device."

The commission has revised the requirements for glycol dehydrator controls and is allowing the monitoring of the combustion control when the dehydrator vents are always directed to that control.

SWEPI commented that, "Condensers Effectiveness should not require testing of process components. Sampling when sample ports exist should be at the discretion of the operator as part of the maintenance program and not a permit condition."

The commission has changed the rule to clarify the requirements that no requirement for any air condenser effectiveness or glycol dehydration unit testing exists. Condenser effectiveness depend s on many parameters. If a glycol control is needed to meet the PBR limitations, there are many voluntary controls/combination of controls that may be selected for various emissions reductions. Glycol dehydration testing is not required. Rich/lean glycol sampling is one method of estimating the glycol dehydrator emissions instead of the common computer program, GLYCalc. One voluntary control would be to once weekly monitor the condenser outlet exhaust temperature to the atmosphere and use GLYCalc to estimate the emissions. Condenser effectiveness depends upon many factors.

The Sierra Club commented that, "The PBR and standard permit should ensure boilers and engines comply with requirements of the Texas SIP."

The commission did not change rule language for this comment. The commission believes that language in the new OGS rules sufficiently indicates that owners and operators must also comply with other applicable rules, including state of Texas SIP rules.

TPA commented on the VRU requirements. "In order to meet the proposed requirements, operators would have to set the VRU to allow the introduction of a substantial amount of additional air. Introduction of large amounts of oxygen into a combustible environment would create unacceptable unsafe operating conditions. In addition, VRUs are proposed for technically infeasible applications, including the control of amine vent stacks."

The commission is not requiring a minimum control efficiency for VRUs in the PBR and agrees that VRUs should never be operated in an unsafe or dangerous manner. If an operator elects to use a VRU for control to meet emission limitations of this rule or to comply with a controlled emission certification, the VRU must be designed operated and monitored to show how it is achieving the claimed control. The commission encourages the use of VRUs where feasible, safe, and appropriate; and operators should not propose them for control where this is not the case.

TXOGA commented that, "Sites with a backup VRU should be able to claim 100 percent capture, and sites without backup VRUs should claim 100 percent for all operations other than planned maintenance, which will vary from site to site. They commented that at, most sites, VRUs, are down only one hour/month for VRU planned maintenance. Other sites are down up to eight hours/month. Any downtime that is not a result of planned maintenance would then be subject to reporting under §101.201 or §101.211."

The TCEQ concurs where an automated backup system is in place and provides redundant assurance of control then 100 percent control can be claimed. Please note the TCEQ wants to encourage recovery over destruction control, but

applicability of control is based on the need to meet emission limitations or certify controlled emissions. Emissions during any down time of a pollution control device when the source is operating normally are considered normal source emissions, not maintenance emissions. If emissions from a source will occur during planned maintenance of a control device, those emissions must be compliant with the emission limitations of the rule.

One individual submitted an article American Oil and Gas Reporter Mar 2005 regarding VRUs.

The commission appreciates the information and has reviewed the article regarding VRUs. As such, many of the issues the article addresses have been included in the VRU portion of the rule.

Hy-Bon stated that "the minimum criteria for a compressor skid to be considered a VRU - consistent with the definitions given for VRU's in workshops given across the country by the Natural Gas STAR program, and the same list presented at the TCEQ Pollution Prevention workshops done in 2008, see article American Oil and Gas Reporter Mar 2005."

Hy-Bon provided details on VRUS. "Requirements which define a VRU: 1) Package must have a pressure sensing device on the tanks or on the skid (typically attached to the tanks via a separate sensing line) which actively monitors gas pressure in the tanks, 2) Package must have a PLC or similar computer system which controls the unit for extremely low pressures (allows automated starts, bypass and shutdown depending on volumes of vent gas), 3) Package must have a bypass system to circulate gas between the compressor and the inlet or suction vessel (allows for unit to run while gas pressure builds back up in the tanks), 4) Package must utilize the correct compressor style for wet gas compression. (rotary vane, rotary screw, scroll or venturi (educator) style compressors can be used effectively; reciprocating compressors are not recommended)- the one exception to this rule are specialty reciprocating compressors utilizing plunger designs specifically designed to capture extremely wet gas streams. These units are generally very expensive and used only in low volume, high discharge pressure scenarios where there is literally no other viable option. The overwhelming majority of reciprocating compressors used in upstream natural gas compression have piston designs which are not effective in wet gas, vapor recovery applications. Is it also important that the production system is properly configured to effectively capture vent gas. 1) Piping from the tanks to the VRU should slope downward with no visible liquid traps (U traps). 2) Tanks should be manifolded together when possible. 3) A gas blanket system should be utilized; sized to backfill gas into the tanks at the same rate at which oil/condensate will be removed. 4) Pressure sensing device should be located on the top of the tanks, or connected to the tanks via a pressure sensing line. 5) All relief valves and tank hatches should be secure and seal properly, properly maintained and in good working order. - see additional details in Gas STAR VRU presentation and the TCEQ workshop VRU presentation."

The commission concurs that VRUs should be properly designed and operated with the correct equipment. The commission does not believe it is appropriate to dictate specific design requirements as suggested, but believes records to show design is adequate and monitoring to show emissions are captured is basic.

Monitoring to clearly show when emissions are released is appropriately enhanced.

Devon commented that, "The proposal allows for 80 percent VRU efficiency with basic monitoring and up to 99 percent efficiency with enhanced monitoring. Sampling and analytical costs are comparable."

TIPRO commented that, "VRU control efficiency default is typically set at 95 percent as a universal default across all state permitting programs. Setting this level at 80 percent appears arbitrary and the rule is unclear as to what the "enhanced monitoring" requirements entail."

EDF commented that, "For claims of control efficiency above 80 percent, a written justification must be submitted to the TCEQ in addition to the proposed enhanced monitoring and testing."

VRUs may claim up to 100 percent control for units where basic design function and additional design parameters are practiced and appropriate monitoring, as listed in subsection (m), Table 8 of this section for vapor capture and recovery, is applied. Subsection (m), Table 8 has been clarified to differentiate the enhanced monitoring requirements. VRUs may claim up to 99 percent control for units where additional design parameters are practiced but monitoring is not applied. For VRUs where only basic design functions are practiced and monitoring is not applied, a control efficiency up to 95 percent will be acceptable. Table 8 in

subsection (m) is being clarified to differentiate the enhanced monitoring requirements. A VRU's design and operation represented in the registration should be consistent with its capability. Enhanced monitoring is proposed to ensure that higher efficiencies are achieved.

SWEPI commented that for "Combustors/Flares One approach is to have a TI {temperature indicator} with auto igniter pilot to claim 90 percent efficiency, then to verify by gas analysis, flow rate, and burner tip velocity that the combustor meets the requirements of 40 CFR §60.18 and a 98 percent destruction efficiency. Although a one-time measurement should be sufficient to demonstrate 40 CFR §60.18 compliance, for MMS {sic MSS} demonstration conditions, a velocity measurement or engineered estimation with a manual blow down condition and also with a VRU out of service condition should be sufficient to support compliance. Also, calorimeters or CEMS analyzers on OGS flares are not economically viable options. The composition is historically high-BTU gas that well exceeds 40 CFR §60.18 BTU requirements and the composition does not change significantly."

The commission has not updated the rule in response to this comment. Neither calorimeters nor CEMS analyzers are required for flares by the rule. The rule does require that the both normal operations and MSS activities are in compliance with all applicable rules including the minimum heating value and maximum velocity requirements to ensure that good combustion which results in the destruction of the waste gas.

Targa commented that the additional requirements. The Additional Requirements for flares in subsection (f)(5): The requirement includes all flares, even emergency flares. Many midstream natural gas compressor stations and gas plants have flares that are used exclusively for emergencies or upset events, specifically when the field pressures up and needs to be relieved. It should be noted that these events are not even allowed to be authorized by NSR permits. The standards of design in 60.18 should not be required. Sonic and ultrasonic flares used frequently in the natural gas upstream and midstream businesses are not able to comply with the velocity requirements in 40 CFR §60.18(f)(4). The EPA has been clear in stating that such flares were not contemplated in 40 CFR §60.18. These flares are well suited for sites with no steam assist, no reliable power for air assist, and are considered a reliable design for 98 percent combustion and smokeless design. The option for these flares should be included in any flare design requirement."

The commission's objective is to assure properly designed and operated equipment is utilized where control is required for the PBR. Engineered sonic and ultrasonic flares were not expected to be common place in the oil field and were not evaluated for this rulemaking. The TCEQ will evaluate appropriate design criteria for these sources and consider adding them in future rulemaking. New authorizations for installation of these devices at sites will require case-by-case NSR permitting.

ETC and TPA commented that, "Emergency flares should be excluded from these provisions because they cannot meet the conditions of 40 CFR §60.18, which is a requirement under subsection (f)(5)(A). New and modified flares used for control of emissions from production or planned MSS, emergency, or upset uses may claim design destruction efficiency of 98 percent and must be designed and operated in accordance with the following."

The commission maintains that flares designed for any purpose including emergency or upset need to effectively and efficiently combust the waste stream. The parameters and requirements in 40 CFR §60.18 have been found to meet the goal of efficient combustion and thus are appropriate to design to for all situations where a standard flare is used. While not every possible emergency or upset can be anticipated an emergency flare's design will be based on the plausible and fail-safe designs of the process equipment and those scenarios can and should fit in the prescribed requirements for flares in this rule. Only the pilot and or sweep gas emissions need to be accounted for in an authorization and all upsets or emergencies should be reported or recorded as appropriate per the air general rules of 30 TAC Chapter 101.

Fasken commented that they have "seen the cost estimates provided by the Permian Basin Petroleum Association to install smokeless combustors on flares, purchase and operate vapor recovery units, and paint tank batteries in reflective colors. Fasken believes the potential costs associated with these proposals would be an economic hardship for many independent operators. Fasken disagrees with TCEQ's analysis that there would be no significant economic effect and states that TCEQ needs to perform an economic analysis as required by THSC, §2001.0225. Fasken is concerned about the immediacy of the implementation of these regulations and that all operators will be scrambling to purchase equipment and get facilities into compliance, adding to the economic hardship. Fasken believes that the heart of the proposal is dramatically lowered standards for VOCs, H_2S, and SO_2. No other gas producing state has limits this low. Fasken proposes that the regulation be withdrawn and a new coordinated effort between TCEQ and the industry begun. Input from the oil and gas community is critical to balanced regulation."

The commission has revised the PBR to not mandate control unless it is necessary to meet emission limitations of the rule. If a company can establish that their facilities and operation at their location are unique and should not need to meet the emission limitations of this rule they may apply for a case-by-case NSR permit.

An individual commented that, "§106.352(f)(5) states that flares used for control of emissions from production, planned MSS, emergency, or upset uses may claim design destruction efficiency of 98 percent. TCEQ guidance "Flare and Vapor Oxidizers, October 2000, RG-109" allows 99 percent for C3 and less. The individual questions which efficiency applies."

The commission revised the rule to allow claims of 99 percent efficiency for combustion of compounds containing only carbon, hydrogen and oxygen with less than three carbon molecules. This was not originally proposed for this rule due the complicating nature of the calculation to establish the maximum potential rate of the two different sizes of compounds and the expectation that only propane would be relevantly adjusted in the evaluation. However, it may be important in

controlling to meet the 25 tpy upper limit of the rule and may become important it methane and ethane control become requirements in the future. Additional records are necessary to address the use of the 99 percent factor and it is not required to be applied if the reduction is not needed to meet the emission limitations of the rule.

TXOGA commented that, "Some of these sites that produce sour gas do not have a way to get sweet gas for the flare pilot. Piping in sweet natural gas will cost millions and is not practical. As long as you meet the PBR, it should not matter if the gas is sweet or sour."

The commission understands that there may be unique situations in remote locations where access to or importing sweet gas for fuel is impractical. The rule was revised to accommodate this potential situation.

EDF commented that, "The TCEQ should establish a firm time limit to repair a leaking component. The Sierra Club commented that, "The timeframes for inspection and repair at PBR-authorized sites are simply too long. Given this significant potential for fugitive emissions in an ozone nonattainment area, the LDAR standards must be more stringent.202.1. ETC states that "In addition, the following changes should be made to subsection (e)(7), related to fugitive monitoring: New and replaced modified fugitive components and instrumentation in gas or liquid service that increase emissions, at the site with and that have the uncontrolled potential to emit equal to or greater than 10 tpy VOC or one tpy H_2S..."

Pioneer stated that "an OGS under the definition in (b)(3) of the proposed rule could encompass a massive area because of the concentration of solely Pioneer wells and tank batteries in certain areas, particularly in Pioneer's Permian Basin operations. It is not clear if this provision is required for an OGS emitting >10 tpy PTE site-wide or >10 tpy PTE from fugitive emissions only. If this is requiring an LDAR program for every OGS with > 10 tpy PTE site-wide, it could be very costly to Pioneer, particularly in the Permian Basin, to monitor thousands of oil and gas facilities to even determine if they are above or below this threshold, then continued monitoring for applicable sites. The benefit of this program in most cases will not outweigh the environmental cost and impact to drive to remote OGS, The EPA is working on a new NSPS and NESHAPS proposal that may include a fugitive monitoring program. Further, EPA has proposed the Mandatory Greenhouse Gas Reporting Rule that requires reporting of greenhouse gas fugitive emissions (if basin exceeds 25,000 tpy C02e). TCEQ, needs to make sure that these rules are consistent with any proposed federal regulations."

ETC states that "This requirement would subject certain facilities to regular audio, visual, and olfactory observation and annual Method 21 testing. Such requirements are inappropriate and unnecessary in a PBR. First, bringing LDAR requirements into the BMP section of the PBR will compromise the voluntary initiatives developed by TCEQ in its 30 TAC Chapter 101 rulemaking. LDAR should be kept in the voluntary incentives program and should not be part of the BMP in the Oil and Gas PBR. In addition, forcing the use of Method 21 would be unnecessary and overly prescriptive; operators should be given the alternative to use equivalent, alternative methodologies in lieu of Method 21."

TXOGA commented that, "Whether or not the LR program is required for an OGS site-wide >10 tpy PTE or fugitives >10 tpy PTE is unclear. If this is requiring an LDAR program for every OGS with >10 PTE site-wide, it would cost industry millions (see fugitives cost estimate) for monitoring hundreds of thousands of dispersed oil and gas facilities. Furthermore, there are not enough monitoring companies in the country to do this work. Monitoring has shown that there are actually very few leakers. Typically under a KKK program less than 2 percent of the components monitored actually leak. The benefit of this program in most cases will not outweigh the environmental cost and impact to drive to remote OGS. Also, the EPA is looking a proposing new NSPS and NESHAPS for oil and gas plus other regulations that may include a fugitive monitoring program for OGS. TCEQ needs to make sure that these rules are consistent with any proposed federal regulations. New and replaced fugitive components and instrumentation in gas or liquid service at the site with the uncontrolled potential to emit of fugitives equal to or greater than 10 tpy VOC or 1 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, other federal regulations, or voluntarily implementing an LDAR program."

EDF noted that they "do not think that the leak detection and repair program to identify and fix leaky fugitive components adequately protects public health. While it may not always be feasible to require monthly or bi-annual monitoring, annual leak detection is grossly under-protective. Quarterly monitoring should be required as a reasonable compromise. TCEQ should require all potential sources of leaks to be inspected. The TCEQ should explain why it proposes that not all equipment at a site should be subject to an LDAR program or to the provisions of this proposed BMP, and why the proposed threshold of 10 tpy VOC is protective. Additionally, the TCEQ should clarify: whether the proposed threshold for uncontrolled potential emissions is for a single component or a site-wide total (we support the threshold being applied to the site-wide total of fugitives); how the calculation of emissions from a leaking component in subsection (e)(7)(D) would be performed if a leak is detected with an optical gas imaging instrument (which we understand is unable to produce quantitative estimates of emissions)."

SWEPI commented that, "Costs for fugitive monitoring may approach $1.25 a component for large facilities; however, this cost can go up by a factor of 5 - 10 for smaller or more remote facilities with under 1000 components because of several factors. First, initial monitoring with Smart LDAR may have a 1 - 4 percent component leak rate with subsequent monitoring being progressively lesser at OGS. In addition, the population density of components at OGS is also significantly less that a manufacturing location. The travel, calibration, and setup for a smaller population, labeling of the fugitive sources, and associated recordkeeping requirements all need to be factored into this cost analysis. Second, traditional Method 21 costs will be largely contingent on leak threshold definition, so this is not an easily quantifiable cost. The leak definition based on emissions 10 - 25 tpy then 10,000 parts per million by volume (ppmv) leak definition, or >25 tpy then 500 ppmv leak definition, is too broad and should consider the proximity to population centers. OGS sites should have the 10,000 ppmv leak definition if they are either small or outside an incorporated population center."

Documentation from the tank manufacturer establishing that the vessel was manufactured according to intended design should suffice. Also, documentation is

needed from the paint manufacturer demonstrating how the paint meets the appropriate solar resistant requirement. Additionally, documentation on how the paint was applied to the vessel should suffice. For existing vessels a recorded visual inspection of tank integrity and conditions should satisfy recordkeeping requirements.

TxOGA stated that, "Other requirements of the Proposed PBR that are overly prescriptive and onerous when compared to other PBRs are listed below. These requirements should be substantially modified to be consistent with the legislative mandate authorizing TCEQ to promulgate PBRs. Those requirements include the following: the Best Management Practices ("BMPs") required under §106.352(e), the mandatory site maintenance program required under §106.352(e)(1), the alternate control or recovery equipment for any planned downtime of any site capture, recovery or control equipment required under §106.352(e)(2), the hourly limits required by §106.352(b)(6)(B), (g), (h) and (k), preconstruction authorization requirements for any OGS with over 10 tons of VOC emissions per year pursuant to §106.352(g)(3) and (h), the prescriptive fugitive monitoring and Leak Detection and Repair requirements under §106.352(e)(6) - (7); the extremely prescriptive and burdensome (and therefore costly) recordkeeping, sampling and monitoring requirements in Tables 7 and 8 of the Proposed PBR. (Tables 7 and 8 appear to be designed for the chemical and refinery industry rather than the exploration and production activities at an OGS)."

The commission has revised the rule in response to several comments and the recordkeeping requirements allow for any documentation that is currently being

maintained that provides the same information will be acceptable.

Sierra Club members "would like the proposed permits to require signage at each OGS stating the name of the owners and operators, listing all pertinent facility registration numbers and permits, and providing contact phone numbers for regulatory agencies. This information is critical for citizens. Currently, it is often very difficult for citizens working or living near OGS to determine who owns or operates the site, particularly when the site is un-manned. The Sierra Club and two individuals requested that the commission modify the proposed standard permit to allow a 30-day public comment period before individual permits are approved."

The commission respectfully declines to change the rule in response to this comment. At this time, the commission does not believe that requiring signs or public notice at OGS is necessary. The notification requirements of all existing facilities and new projects will give the agency and public a comprehensive listing of locations which can be used to identify an OGS. The public can access information about a certain site by contacting their local regional office or by accessing it on the TCEQ website, which is updated each day for pending and completed registrations and applications. The remote document server is where many agency generated documents are available within days of completion and includes the actual technical review of each applicant's registration. Finally, sign posting at well locations would be redundant with the Texas Railroad Commission rule in 16 TAC §3.3 which require signs posted at entrances, wells, and tanks listing the name of the operator and other identifying information.

D. Enforceability

Senator Davis stated "the proposed regulations should be carefully reviewed to ensure their intent is put into practice and no weaknesses or openings are left to be exploited. This is needed to protect public health and to ensure that conscientious owners and operators are not disadvantaged by those cutting corners or gaming the system."

The commission appreciates the comment and has spent hundreds of man-hours on this rule project to ensure a practically enforceable authorization which is protective of public health and welfare. The regional investigators state that the current rule is so broad in scope that it is difficult to write violations under §106.352 for exercising poor operating practices. Often times, investigators have little to rely on, even when citing §106.4(c). Section 106.4(c) states that "the emissions from the facility shall comply with all rules and regulations of the commissions and with the intent of the TCAA." The new rule has been developed to encompass all possible operating scenarios, as well as the ways in which those operations should be conducted. With more explicit expectations, it is the intent of the commission to not only allow more operational flexibility, but also outline the types of practices deemed adequate. As such, the new rule with offer investigators more platform to cite companies who are not operating appropriately. It also gives clear expectations to the companies, especially those who operate in a conscientious manner, what they should have to demonstrate their compliance.

The Sierra Club expressed concerns that "The flexibility in the standard permit and PBR allow the same type of equipment at different sites to have a huge variation in emissions. This lack of a unit-specific limit impedes enforceability."

The commission has not changed the PBR or standard permit rules in response to this comment. The commission has historically authorized groups of similar facilities under a single standard exemption, PBR, or standard permit. The commission understands that emissions from the same unit may vary greatly depending on the operating scenario. Instead the intent is for those emissions to be protective of the public. The commission agrees that the OGS PBR and standard permit rules provide flexibility for meeting the rules. The rules also ensure practical enforceability along with providing flexibility.

ETC commented that, "The proposed PBR contains unduly onerous recordkeeping requirements. Proposed §106.352(j) will require that various records be maintained and readily available to regulatory officials upon request. The recordkeeping requirements would apply to a myriad of plant activities as listed in Tables 7 and 8. This is an extensive set of recordkeeping requirements and is onerous and burdensome. For a PBR to be useful, it must be free from unreasonably burdensome requirements, including those relating to documentation and recordkeeping."

TPA commented that, "The proposed PBR contains unduly onerous recordkeeping requirements.

TXOGA commented that, "The tables for sampling, monitoring, and recordkeeping will cause immediate non-compliance across the state as there is a lack of industry personnel, equipment, and contractors to complete the proposed requirements (Tables 7 and 8 to be enclosed) (392,924 oil and gas wells that could be affected by these requirements across the state).

TXOGA commented "The proposed sampling, compliance demonstration, and monitoring and record keeping requirements discussed are extremely onerous and difficult to implement for the thousands of dispersed unmanned locations. These requirements will cause immediate non-compliance across the state as there is not enough a personnel, equipment, or contractors to complete the requirements."

Encana supports the innovative approach to permitting concerning compliance demonstrations.

Encana stated that the commission should "consider the practical enforceability of gas and liquid sampling requirements.

One individual commented that the rule "needs more specific citations to clarify the requirements for 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. Is this total sulfur or H_2S concentration or a complete speciation? Also need to clarify the requirements necessary to meet TCEQ objectives regarding site production or collection of natural gas, oil, condensate and water production records, Site inlet and outlet gas volume and sulfur Concentration."

TAEP commented that, "Oil and gas operators report production monthly to the Texas Railroad Commission. It is a sworn statement. It is verifiable. It is re-certified by the Comptroller. We pay taxes on it. Production volumes are not secrets. Additionally, we would suggest that a separator is a separator is a separator. They are not uniquely different. The same is true of 210 barrel production tanks and fiberglass water tanks. If one knows the volume of fluids and the pressure, then calculation of potential fugitive emissions is an easy matter. Surely, this reporting can be reduced to a simple global positioning system position with a one page form maintained in file by the operator stating volume of production, pressures and equipment on site."

The PBPA commented "All oil and gas operators will be required to create and maintain a detailed and expansive (and thus expensive) environmental emissions inventory for each and every production facility (30 TAC Chapter 116 . . . and by explicit and/or implicit reference throughout the document). There is no provision in the new rule that limits the level of technical rigor that TCEQ could impose for the required site-by-site air emissions inventory and analysis. The TCEQ could dictate by "guidance" (which requires no public hearing, no consideration of public comments or other accountability) the specifications (and thus logistical and financial costs) for such inventories. Of major concern is that TCEQ will require detailed (extensively speciated) laboratory analysis of all process fluids (oil, gas & produced water) streams as well as direct on-site and detailed measurement of all emission sources (tank vents, fugitive & truck emissions, flares, amine units, etc.)."

Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8). The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to the those specified.

Devon commented that, "The proposals require an excessive amount of recordkeeping, reporting, monitoring, and best management practices that will achieve minimal emission reductions at an overwhelming cost and burden to industry. As such, these requirements are impractical, economically infeasible, unreasonable and unjustifiable. Specific examples with recommended alternatives are listed in the Detailed Technical Comments section."

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "Burdensome recordkeeping and would reduce the number of these used in the field typically at sour gas locations to avoid H_2S seepage.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko requested that the commission "delete the requirement for site inlet and out let gas volume. There is no need for like-kind changes, §106.8 recordkeeping already tickets requires records and is redundant. Please remove from the trucks that pick up the fluids from the tanks. Production reporting requirements production and recordkeeping requirements are not necessary. The records are required for only monthly production. Data would be available upon request. Data production shall be maintained at the nearest manned location."

Devon commented on Table 8: Monitoring and Records Demonstrations: "The requirement to keep records of like-kind replacements should be struck from the rule, as like-kind replacements have no impact on emissions. Similarly, the requirement to keep records of "minor" changes at a site is not warranted, since any change that increases the potential to emit will require the site to re-register."

Encana commented on Table 8 in §106.352 and Standard Permit- Category - Minor changes "Records showing all replacements and additions, including summary of emission type and quantities. Encana Response: Encana seeks clarification from TCEQ that only those changes that increase emissions above the thresholds proposed in subsection 106.352(c)(1)(B) of the PBR and subsection (c)(1)(C) the Standard Permit are subject to the recordkeeping requirements."

Encana commented on Table 8, PBR §106.352 and Standard Permit - Category . . . Site Production or Collection – "Site inlet and outlet gas volume and sulfur concentration, daily gas/liquid production and load-out from tanks. Encana response: Encana is unaware of any emission estimation calculation which utilizes "site inlet gas volume." Sulfur emission calculations are independent of "site inlet gas volume," The requirement to record "site inlet gas volume" should be stricken from the proposed rules. Liquid production at oil and gas facilities is not continuously measured. Therefore, daily liquid production can only be calculated from run tickets when liquids are hauled, Daily gas production from tank is a calculated, not monitored, value from the liquid hauled volumes. There is no value in calculating liquid or gas production on a daily basis. The EPA is clear that compliance demonstrations can be done monthly. Production volumes and emission calculations should be required on a monthly basis. Encana proposes the addition of the following language: "Data that is routinely collected as part of normal operations and/or printouts of production reports submitted to federal or state agencies are sufficient to meet this requirement." Encana Response: Encana seeks clarification from TCEQ that only those changes that increase emissions above the thresholds proposed in subsection 106.352(c)(1)(B) of the PBR and subsection (c)(1)(C) the Standard Permit are subject to the recordkeeping requirements."

TIPRO commented that, "The requirement for "Site inlet and outlet gas volume and sulfur concentration, daily gas/liquid production and load-out from tanks" is overly proscriptive and does not consider routine oil and gas operations. Producers are unaware of any emission estimation calculation which utilizes "site inlet gas volume." Liquid production at oil and gas facilities is not commonly measured on a continuous basis. The EPA is clear that compliance demonstrations can be done monthly. The requirements to record "site inlet gas volume" should be stricken from the rule."

Encana commented that they would "welcome the opportunity to work with the Agency to better define the necessary sampling, monitoring and recordkeeping to demonstrate compliance with the proposed rules."

The commission respectfully declines to change the rule language in response to these comments, except for a change to recordkeeping requirements for total negligible changes. Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8). The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The site in-let and production records are needed to help the site demonstrate compliance with the PBR. Any changes to production at the site can be noted by these records, which are given to the Texas Railroad Commission. Then changes can be adequately reviewed by the owner/operator to insure compliance with the rule. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. Documentation that is currently being maintained that provides the same information will be acceptable.

Encana commented that they would "welcome the opportunity to work with the Agency to better define the necessary sampling, monitoring and recordkeeping to demonstrate compliance with the proposed rules."

Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8). The details provided in this PBR are designed to clarify the appropriate monitoring methods,

sampling, and the records required to meet that general requirement as outlined in §106.8.

Exterran commented that, "The Texas Clean Air Act modification exemption for maintenance and replacement components should apply to the engine replacement and will not impede progression of better performing engines and lower engine standards on existing SI RICE (Section D). The Texas Clean Air Act ("TCAA") allows TCEQ to adopt permit by rules to authorize a "new facility" or to "modify an existing facility" that "will not significantly contribute air contaminants to the atmosphere." Further, the TCAA specifically exempts from the definition of "modification of existing facility" any "maintenance or replacement of equipment components that do not increase or tend to increase" or change emissions. Id. at THSC, §382.003(9). The engine is just one component of the facility that drives the compression of natural gas. The compression facility consists of integral engine components such as the engine, engine cooler, engine exhaust, and wiring. As with any facility, equipment must undergo routine maintenance and repair to ensure optimal operation, in which this case would involve removing the core engine portion of the facility and replacing that engine with a similar make/model to minimize downtime as well as provide a higher level of maintenance for the overall facility. Consistent with these TCAA provisions, the routine replacement of just the engine portion of the facility (and not the associated cooler, exhaust or wiring portions) does not "significantly contribute to air contaminants" and should not be considered a "modification to an existing facility" or a "new facility" that requires reauthorization under a new PBR due to the replacement alone. Recommendation: Clarify that the Proposed PBR and Standard Permit apply the TCAA replacement exemption from modification to engine-only maintenance replacements that do not increase or change the character emissions. Specifically, the respective proposals should be amended to read as follows: Proposed PBR. The Proposed PBR should be amended by deleting Proposed PBR §106.352(e)(4)(A) and moving it to a new Proposed PBR §106.352 (f)(7) to read as follows, " Engines (excluding replacement engines that do not increase the previously registered emissions or potential to emit emissions) and turbines shall meet the emission and performance standards listed in Table 9 in subsection (l) of this section.""

The commission respectively declines to change the rules in response to this comment. A replacement engine is a new facility and must meet the requirements of the PBR rule, unless otherwise specified. A new engine must meet applicable federal requirements.

Exterran commented that, "When the engine is the only component of the facility replaced during maintenance, requiring a new authorization n for the replacement of an engine seems to discourage the very replacement, repair and maintenance encouraged by the TCAA modification exclusion. Additionally, state and federal engine standards which impose additional criteria and HAPs emission reductions on virtually all SI RICE should also be considered. Imposing "new authorization" requirements upon replacement engines already subject to aggressive state or federal law will create duplicative and conflicting requirements. Recommendation: Clarify that the Proposed PBR and Standard Permit apply the TCAA replacement exemption from modification to engine-only maintenance replacements that do not increase or change the character emissions. Specifically, the respective proposals should be amended to read as follows: Proposed PBR. The Proposed PBR should be amended by deleting Proposed PBR §106.352(e)(4)(A) and moving it to a new Proposed PBR §106.352 (f)(7) to read as follows, " Engines (excluding replacement engines that do not increase the previously registered emissions or potential to emit emissions) and turbines shall meet the emission and performance standards listed in Table 9 in subsection (l) of this section.""

The commission respectfully declines to change the rules in response to this comment. A replacement engine is a new facility and must meet the requirements of the PBR rule, unless otherwise specified. A new engine must meet applicable federal requirements. The commission deleted engine testing requirements for VOC and formaldehyde in response to other comments.

Exterran noted that "in addition to the Texas Clean Air Act general permitting requirements, recent state and federal regulatory requirements for SI RICE continue to promote aggressive emission standards on engines regardless of authorization. In other words, on top of the routine replacements which maintain or improve engine performance under the existing Standard Permit and PBR authorizations, SI RICE are now also subject to a more stringent state and federal emission standards and operation requirements. The following state, federal NSPS and NESHAP regulations have created lower, more stringent emission standards or management practices on SI RICE: Chapter 117 of the Texas Administrative Code imposes lower NO_X standards on certain SI RICE engines. NSPS imposes lower NO_X and VOC emission standards on new or reconstructed engines. 40 CFR Part 60, Subpart JJJJ. NESHAP has recently imposed hazardous air pollutant emission standards which will require catalytic control requirements on virtually all new and existing SI RICE greater than 500 hp and management practices for many engines less than 500 hp. 40 CFR Part 63, Subpart ZZZZ. Instead of imposing potentially duplicative and costly emission standards on existing SI RICE, replacement SI RICE should be subject to the applicable state and federal requirements already in place to impose emission reductions on existing engines. Reliance on existing state authorizations, in addition to Texas and federal engines standards, avoids disproportionately impacting replacement engines in Texas when compared to other states which must only comply with federal standards."

The commission notes that they must consider different standards for updating PBRs and addressing nonattainment areas of the state. The EPA must consider different criteria when promulgating 40 CFR 60 NSPS, 40 CFR 63 MACT or 40 CFR 61, 63 NESHAP rules. The proposed PBR rules stated that owners or operators must be in compliance with any state, federal or local rules. The PBR has been revised so that compliance with another state or federal rule, is compliance with the PBR. Therefore, this will minimize any additional cost or recordkeeping to industry.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "Unrealistic burden for small E&P sites. Strike from rule based on irrelevance to protecting health and the environment. As-built drawings are not necessarily made on site-by-site basis; however, equipment specs can be maintained at the nearest manned location. Some small sites are built upon design templates; detailed as-built drawings are not necessarily readily available. However, they can be generated at the request of the agency. If the Level 2 requires preconstruction authorization, how can a as built plot plan be submitted with the application? "

TIPRO commented that the term "As-built plot plan" in table 8 is not defined.

Devon commented on Table 8: Monitoring and Records Demonstrations Equipment and Facility Summary - Current process description. "The proposed rule requires an as-built plot plan with property line, off-site receptors, and all equipment on site. Plot plan drawings are not typically performed for most OGS, particularly remote sites. Devon suggests that plot plans can be made available upon request by TCEQ where it is deemed necessary to determine off-site emission impacts, etc."

The commission has changed the rule in response to this comment to require an accurate and detailed plot plan (or equivalent, such as acceptable design templates) of equipment at the site. To ensure that emission estimates accurately reflect the facilities which are being registered and authorized, detailed equipment and infrastructure information is necessary. However, the commission has not required that the plot plan be drawn up by a professional draftsman. Any drawing that is accurately representative of the site will suffice.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko stated that the "commission should ensure "nearest manned facility" language is included. All items are NOT necessary to protect health and the environment. Include only volumes, pressure, and flows pertinent to performing emissions calculations in the permit application. All else is irrelevant. Basic sizing specs on flares, VRUs, dehydration units could be kept at the nearest manned site or company headquarters available upon request."

The commission respectfully declines to change the rule in response to this comment, but emphasizes that records are needed for both the calculation data and the actual site data to check compliance.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "An emission threshold should be established for documenting changes. Non-PSM facilities do not track minor changes. (Section) 106.261 (5 tpy threshold) reiteration, §106.264 replacement of facilities for like-kind changes, §106.8 recordkeeping already requires records and is redundant. Please remove from the rule."

The commission respectfully declines to delete replacement and recordkeeping requirements from the new OGS rules. The commission understands the comments about PBRs §106.264 and §106.8 to mean to please pull replacement of facility requirements and recordkeeping requirements from the new OGS rules. The thought is that PBRs §106.8 and §106.264 already addresses replacement of facilities and addresses recordkeeping requirements for the new OGS PBR rule. However, the new OGS rules have more specific replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements are needed for practical enforceability. Additionally, combustion units and most, if not all, other unit types at oil and gas, do not qualify for PBR §106.264, due to the presence of compounds at OGS that are listed in Appendix VIII of 40 CFR Part 261.

The commission does not change the rules in response to this comment to add emissions thresholds for when documentation (i.e., recordkeeping) is not required261. Recordkeeping, including the recordkeeping for several small changes occurring over specified periods of time, is required for practical enforceability and for demonstrating compliance with the requirements of the OGS.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko suggested "Redraft the records section for planned MSS to make it more clear. TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko suggested to "Re-draft the records section for planned MSS to make it more clear. Remove the two volumes of purge gas portion since this is not a record keeping requirement. Unclear as written: Maintaining records of purge gas entrance and exit points is overly burdensome and brings about no improvement in air quality in the State of Texas. The purge gas requirement is not a record keeping requirement and should be struck from Table 8. These requirements are already present in 30 TAC §101.211. For planned events, such as turnarounds, operations will have to keep a log book. Documentation of planned MSS is redundant with above; we'll be quantifying emissions, which serve as documentation. "Unplanned" MSS must be struck; we do what is required under STEERS. "Compositions of emission released" must not require sampling. Estimating emissions is adequate without sampling."

The commission has changed the tables and rule language to make expectations and requirements more clear. The purge gas requirement has been deleted.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko requested that the commission "delete the requirement for site inlet and out let gas volume. There is no need for the inlet and out let gas volume in the calculations if you are already requiring production of gas. Production of oil, condensate, and water are not measured with a flow meter. They are accounted for using run tickets from the trucks that pick up the fluids from the tanks. Production reporting requirements already exist under the Texas Rail Road Commission; therefore, additional production recordkeeping requirements are not necessary. The records are required for only monthly production. Data would be available upon request. Data production shall be maintained at the nearest manned location."

TIPRO commented that, "The requirement "Records showing all replacements and additions that result in an increase of more than 1 tpy VOC, 5 tpy NO_X, 0.01 tpy benzene, and 0.05 tpy H_2S, including summary of emission type and quantities" is unrealistic and has no significant impact on emissions. Fugitive counts and AP-42 emission factors are conservative and as stated in the MAERT table "fugitive emissions are estimates." There is no environmental benefit to be gained compared to the burden of tracking all minor valves and fitting change at an oil and gas site."

Devon commented on Table 8: Monitoring and Records Demonstrations Minor Changes Ft Equipment Replacements: "The requirement to keep records of like-kind replacements should be struck from the rule, as like-kind replacements have no impact on emissions. Similarly, the requirement to keep records of "minor" changes at a site is not warranted, since any change that increases the potential to emit will require the site to re-register."

The commission respectfully declines to change the rule language in response to these comments. Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8) The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. Any documentation that is currently being maintained that provides the same information will be acceptable. Submittal of data is required as specified to support reviews or audits of registrations and to ensure practical enforceability. Based on the commission's experience with review of numerous OGS registrations, gas flow rates, and minor changes are needed for accurate emissions calculations and site wide representations. The rules do allow for some increases in emissions without requiring registration. For practical enforceability, the recordkeeping is needed for changes that do not trigger registration requirements.

TIPRO commented that, "The requirement for "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" is extremely burdensome to operators and should be reserved for the highest emitting facilities.

This requirement should only be required for facilities that emit greater than 80 percent of Part 70 Major Source thresholds. The table should clarify that only data necessary to calculate planned MSS emissions is required."

Encana commented on Table 8 located in PBR §106.352 and Standard Permit - Category - Equipment Specifications "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, Encana Response: This requirement is extremely burdensome to operators and should be reserved for the highest emitting facilities, Encana asserts this requirement should be only be required for facilities that emit greater than 80 percent of 40 CFR Part 70 Major Source thresholds."

The commission changes the language in the rules in response to this comment. The commission better clarifies appropriate records for planned MSS activities. Where vessels are to be de-pressured and cleared for maintenance substantial emissions can be released into the air depending on the approach used by the operator. The PBR rule does not limit the frequency or require controls of MSS. The PBR rule does require controls if they are needed to meet protectiveness requirements. Recordkeeping for MSS activities is needed for practical enforceability. The commission did not change the rules for MSS to be directly based major source thresholds. The commission notes that the regulatory need

for updating §106.352 and consider for nonattainment areas of the state is different than what the EPA must consider when promulgating PSD or NNSR rules.

Encana commented on Table 8 PBR §106.352 and Standard Permit- Category - Minor changes "Records showing all replacements and additions, including summary of emission type and quantities. Encana Response: Encana seeks clarification from TCEQ that only those changes that increase emissions above the thresholds proposed in subsection 106.352(c)(1)(B) of the PBR and subsection (c)(1)(C) the Standard Permit are subject to the recordkeeping requirements."

The commission respectfully declines to change the OGS PBR rule in response to this comment. Recordkeeping, as specified, is required for subsection (c)(1)(B) and (C). The commission moves and addresses the content of subsection (c)(1)(C) under subsection (c)(1)(B). The new OGS rules have more specific replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements, as opposed to the vague recordkeeping requirements of PBR §106.8, are needed for practical enforceability. Recordkeeping, including the recordkeeping for several small changes occurring over specified periods of time, is required for practical enforceability and for demonstrating compliance with the requirements of the OGS rules.

Changes, especially new equipment are modifications requiring evaluation and

normally always requiring authorization. The commission is allowing some adjustment with appropriate minimum potential for impact concern in all cases to skip or delay the authorization process. Every site should be aware of their emission potential and equipment at every site. The commission is not requiring leak no leak monitoring as described in the fugitive documents in AP-42 to account for fugitive emissions. Simple counts with the less conservative oil and gas factors are allowed and are easy to track. Since each OGS can be very different with respect to its distance to receptors and property line, this simple accounting procedure is necessary to assess potential emissions and check impact protectiveness.

The commission does not delete replacement and recordkeeping requirements from the new OGS rules in response to this comment. The new OGS rules have more specific replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements, as opposed to the vague recordkeeping requirements of PBR §106.8, are needed for practical enforceability. Recordkeeping, including the recordkeeping for several small changes occurring over specified periods of time, is required for practical enforceability and for demonstrating compliance with the requirements of the OGS rules.

Encana commented on Table 8 in PBR §106.352 and Standard Permit- Category - Minor changes "Records showing all replacements and additions, including summary of emission type and quantities. Encana Response: Encana seeks clarification from TCEQ that only those changes that increase emissions above the thresholds proposed in §106.352(c)(1)(B) of the PBR and subsection (c)(1)(C) the Standard Permit are subject to the recordkeeping requirements."

The commission does not change the OGS PBR rule in response to this comment. Recordkeeping, as specified, is required for subsection (c)(1)(B) and (C). The commission moves and addresses the content of subsection (c)(1)(C) under subsection (c)(1)(B). The new OGS rules have more specific replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements, as opposed to the vague recordkeeping requirements of PBR §106.8, are needed for practical enforceability. Recordkeeping, including the recordkeeping for several small changes occurring over specified periods of time, is required for practical enforceability and for demonstrating compliance with the requirements of the OGS rules. For practical enforceability, the recordkeeping is needed for changes that do not trigger registration requirements. Additionally, replacement facilities are new facilities.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko expressed concerns regarding "Worst-case is not representative of site condition and therefore will grossly overestimate emissions. As stated this requirement could be taken to mean any pressure vessel within the facility and not vessels that have affects on emissions."

The commission concurs that the record requirement could be misinterpreted to apply where no emissions are expected. To clarify the commission moves the

record to tanks / vessels where the pressure from which a flash originates. The commission considers emissions from a pressure vessel to be emergency or upset emissions if the emissions are not normal or MSS emissions. Additionally, the commission considers emissions that are not normal or MSS emissions to be upset or emergency emissions. These upset or emergency emissions are not authorizable under the OGS rules.

Encana commented that, "Table 8 in PBR §106.352 and Standard Permit - Category - Planned Maintenance, Startup, and Shutdown (MSS) - 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,...Encana Response; This language is unclear. It appears the language requires VOC sampling to verify VOCs are purged from vent lines prior to bypassing control devices. If this is the case, this requirement unnecessarily subjects operators to safety hazards of fire or explosion with limited environmental benefit. Operators do not access waste gas vent lines now, this is unnecessary risk and should be stricken from the proposed rules. There is no consideration from (sic for) small, remote facilities operating in rural attainment areas, Requirements such as this should be reserved for large facilities, such as compressor stations and gas plants, in nonattainment areas."

The commission revises the requirements to clarify record keeping. There are no

mandatory controls or purging requirements for the PBR. Where all material is purged to atmosphere the record will simply indicate the emission associated with the pressure and volume purged. If control is necessary to meet emission limitations or certify controlled MSS emissions, the record would indicate the control device and those emissions in addition to the emissions when the equipment is then opened to the atmosphere. If it is necessary to further purge equipment to reduce emissions beyond simple de-pressuring to control, the concentration prior to opening to atmosphere must be measured to confirm the emission associated with the atmospheric purge. Note the concentration measurement is only necessary when saturated vapor purging at atmospheric opening pressure and purge will not meet emission limitations or a lower emission is certified.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated that "the proposal included burdensome recordkeeping. The trucking company is responsible for their trucks. The tank level is not gauged after the loading event and is unnecessary. The Texas Railroad Commission has jurisdiction of produced fluids. As written the delivery of antifreeze to the site would require this unnecessary record. They proposed language changes: "The Operator shall maintain the appropriate condensate and crude records as required by the Texas Railroad Commission or monthly run tickets and shall be made available upon request.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Trucks are not owned by the owner/operator of the oil and gas site and therefore not the responsibility of the operator. Any requirement needs to be directed towards the owner of the tank truck. Recommend: "Records of tank truck certifications and testing shall be maintained by the owner/operator of the tank truck. Records are only required if connection to control is used and credit is claimed for certified truck use.""

The commission has made these truck loading recordkeeping requirements mandatory only if the company is claiming a control or if particular parameters in the calculation method are necessary to meet the emission limitations. The loading records are associated with the site owner/operator who is claiming authorization for the emissions under this rule since the truck loading rack is located on the site. The commission notes that the method used to transfer the liquids from the storage tanks to the trucks and the quantity loaded directly relates to how a company calculates its emissions. For example, the mode of operation of the tank truck affects the saturation factor used to determine the emission rate as indicated in AP-42, Chapter 5, and Table 5.2-1. In addition, truck contents prior to loading and the condition of the tank truck will affect the emission rate hourly and annual emission rates. Without records of this information, it is not possible to accurately estimate emission rates to ensure that the emissions are below the PBR limits or to verify that the emissions are protective. The commission does not have regulatory authority the over trucking companies. Companies may form an agreement with the trucking company on the documentation system that is most convenient for the site and truck operators that captures the pertinent information used as the basis for the calculating emissions. Antifreeze delivery is different from the truck loading of oil and natural gas liquids. The commission is

not as concerned about the emissions associated with antifreeze because of its use and characteristics. Antifreeze is trucked to the site in limited quantities and not transferred through a loading rack in high volumes. Additionally, antifreeze has a low vapor pressure and a high molecular weight which also means that emissions from unloading antifreeze are not of the same magnitude as seen with loading of oil and natural gas liquids.

Recordkeeping

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko requested clarification on "What constitutes a "record of maintenance of paint color and vessel integrity." Clarify that the color requirement does NOT apply to Process Vessels, but rather Storage Vessels. Non-emitting equipment, such as enclosed pressurized process vessels, should NOT have a solar absorptance specification since there are no direct emissions from these equipment types."

The commission changes the rule to indicate that controls are voluntary unless controls are needed to meet emission limitations or certify emission controls. Documentation from either the tank manufacturer or paint producer establishing that the vessel was manufactured according to intended design should suffice. Additionally, documentation demonstrating that the paint applied to the vessel meets the appropriate solar resistant requirement should suffice, as well. For existing vessels a recorded visual inspection of tank integrity and conditions should satisfy recordkeeping requirements.

TXOGA stated that, "Other requirements of the Proposed PBR that are overly prescriptive and onerous when compared to other PBRs are listed below. These requirements should be substantially modified to be consistent with the legislative mandate authorizing TCEQ to promulgate PBRs. Those requirements include the following: the Best Management Practices ("BMPs") required under §106.352(e), the mandatory site maintenance program required under §106.352(e)(1), the alternate control or recovery equipment for any planned downtime of any site capture, recovery or control equipment required under §106.352(e)(2), the hourly limits required by §106.352(b)(6)(B), (g), (h) and (k), preconstruction authorization requirements for any OGS with over 10 tons of VOC emissions per year pursuant to §106.352(g)(3) and (h), the prescriptive fugitive monitoring and Leak Detection and Repair requirements under §106.352(e)(6)-(7); the extremely prescriptive and burdensome (and therefore costly) recordkeeping, sampling and monitoring requirements in Tables 7 and 8 of the Proposed PBR. (Tables 7 and 8 appear to be designed for the chemical and refinery industry rather than the exploration and production activities at an OGS)."

The commission revises the rule in response to several other comments about the same subsections in this comment. The commission respectfully declines to change the OGS PBR rule directly in response to this comment. The commission believes the final OGS PBR rule is consistent with legislative mandates for promulgating PBRs. The recordkeeping requirements allow for any documentation that is currently being maintained that provides the same information will be acceptable.

EDF commented that, "In order to document the performance requirements of flare systems in (A) – (E), a new subsection (H) should be added that requires use of a recording system to document adequate combustion and the output of required devices such as the infrared monitor, thermocouples, etc. Otherwise we support this subsection as proposed."

The commission appreciates the support. Records of thermocouple, infrared monitor or auto-ignition sparking device are required in Table 8 as mandated in subsection (j).

Exterran commented on "352(i)(3)(A) and Proposed Standard Permit 352(i)(3)(A). In lieu of duplicative, extensive and additional recordkeeping requirements for operations which do not create MSS emissions, TCEQ should qualify that MSS record keeping requirements only apply to activities where emissions are created that exceed *de minimis* criteria."

The commission changes the rule in response to this comment, by adding to subsection (j) "any documentation that is already being kept for other purposes will suffice for demonstrating requirements." Based on statements from commenter's and stakeholders, the commission understands that most operators pay attention and in their best interest to keeping equipment in good working order and therefore any company records showing these activities will suffice, creating a negligible burden on operators and ensuring no duplication of requirements. However, the commission does not change the rule by adding DeMinimis criteria for when recordkeeping is needed. The new OGS rules have

more specific replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements, as opposed to the vague recordkeeping requirements of PBR §106.8. Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8) The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified.

Exterran commented that the "TCEQ should allow owners and operators to rely on existing recordkeeping requirements for SI RICE to document activities, such as those listed in the Proposed PBR and Proposed Standard Permit §106.352(i)(3)(A) that create little, if any, emissions over insignificant or minimal thresholds. NSPS currently requires owners and operators of SI RICE at major sources to develop and comply with preventive maintenance plans. 40 CFR Part 60, Subpart JJJJ. Likewise, NESHAP regulations require management practices for all engines under 500 hp at NESHAP Area Sources. 40 CFR Part 63, Subpart ZZZZ. The NESHAP management practices require records for oil analysis and changes, spark plug inspections and belt and hose inspections."

Devon commented that, "The proposed rule requires recordkeeping for routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, and spark plug changes, which result in a significant burden on the operator with no environmental benefit. Devon strongly recommends that recordkeeping be performed on items that pertain directly to air emissions, such as emission control system maintenance. In the event additional maintenance items must be documented, the requirements should only apply to the larger engines, such as 500-hp and greater, which is consistent with the recently passed existing engine rule, NESHAP, Subpart ZZZZ."

The commission changes the rules in response to this comment. The commission has included alternatives in the rules including any documentation that is currently being maintained that provides the same information will be acceptable. Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8 and 40 CFR 63 MACT ZZZZ) The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. Any documentation that is currently being maintained that provides the same information will be acceptable.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko recommended to, "Strike §106.352(i)(3)(D) on the basis that this requirement has no protective impact on the environment. This particular rule citation is covered under §106.352(e)(1)(B), "cleaning and inspection of all equipment"."

The commission agrees with this comment. The commissions deletes the language of subsection (i)(3)(D) from the rule and renumbers has renumbers the section accordingly.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested to "Strike §106.352(i)(3)(E) on the basis that this requirement has no protective impact on the environment. Amine is an aqueous solution with an extremely low vapor pressure. To generate 1 tpy VOC would require off-loading over 4 MMGAL of amine. Using Loading Loss Eq for removing Amine/Glycol/Lube Oil from system. The amount required to get 1 ton VOC is equal to: Amine - 4.5 MMGAL; Glycol (TEG) - 450 MMGAL; Lube Oil - 1 MMGAL at 0.5 psia VP."

The commission agrees with this comment, the short-term impact potential is very small for this activity as noted by the calculations above associated with pulling all the amine from a system. A record of maintenance goes hand in glove with the concept proper operation and maintenance. If amine filter replacement is not conducted, problems with the amine system can occur resulting in upset release with or without control which is environmentally significant.

The commission does not change the rule by adding *de minimis* criteria for when recordkeeping is needed. The new OGS rules have more specific replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements, as opposed to the vague recordkeeping requirements of PBR §106.8, are needed for practical enforceability. Recordkeeping, including the

recordkeeping for several small changes occurring over specified periods of time, is required for practical enforceability and for demonstrating compliance with the requirements of the OGS rules. The commission recognizes that the magnitude of emissions from some MSS activities do not have effects on impact reviews, and only recordkeeping is required for such MSS activities. Also, as per the USEPA, rules need to be exclusive and inclusive, and, therefore, MSS activities that are not specifically addressed in the OGS rules are not authorized.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "It can be agreed upon that the emissions from the sources deleted are insignificant and impossible to quantify with any degree of certainty. Keeping records of usage for these activities does not provide a health benefit or air pollution reduction, and only serves to increase the recordkeeping burden on insignificant activities."

The commission will accept any documentation that is currently being maintained that provides the same information. It is not impossible to quantify and these activities are absolutely imperative to insuring the proper operation of equipment to meet the critical emission limitations. There are sources in the rule requirements which have a quantifiable amount of potential emissions and these sources and facilities are retained in the rule.

However, the commission does not change the rule by adding DeMinimis criteria for when recordkeeping is needed. The new OGS rules have more specific

replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements, as opposed to the vague recordkeeping requirements of PBR §106.8, are needed for practical enforceability. Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8) The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. The commission recognizes that the magnitude of emissions from some MSS activities does not have effects on impact reviews, and only recordkeeping is required for such MSS activities.

EPA recommends that TCEQ add a condition §116.620(f)(6) and §106.352(f)(6) to state "OGS must report annually to TCEQ all emission data from each emission source and speciate all VOCs."

The commission respectfully declines to change the rule in response to this comment. The TCEQ utilizes separate rules and program, Emission Inventory, in gathering annual emissions data. In analyzing potential impacts for the most common compounds, only natural gas, crude oil, condensate, benzene, formaldehyde, NO_X, SO_2, and H_2S were found to control impact concerns, and only those pollutants need to be evaluated for maximum allowable emission rates and

impacts analysis. This authorizes construction where emissions will meet the limitations and is not an accounting mechanism for actual emissions.

Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8). The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. The phrase "or approved equivalent" has been added to the detailed monitoring conditions throughout the permit. Recordkeeping- Any documentation that is currently being maintained that provides the same information will be acceptable.

TXOGA commented "The proposed sampling, compliance demonstration, and monitoring, and record keeping requirements discussed are extremely onerous and difficult to implement for the thousands of dispersed unmanned locations."

Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8). The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or

recordkeeping methods that were overlooked and that are equivalent to those specified. For recordkeeping, any documentation that is currently being maintained that provides the same information will be acceptable. Otherwise, the commission does not change the rule language in response to this comment. The commission agrees that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this comment and other comments including comments about the stringency of PBRs should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training.

TXOGA continued, "These requirements will cause immediate non-compliance across the state as there is not enough personnel, equipment, or contractors to complete the requirements."

The commission will take any other paperwork that demonstrates these records. Many of these records are being kept for other reasons or state agencies. It is the commission's intent to not create duplicative paperwork.

Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8). The details

provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. For recordkeeping, any documentation that is currently being maintained that provides the same information will be acceptable. Otherwise, the commission does not change the rule language in response to this comment. The commission believes that after the changes to the rule in response to comments, compliance with the OGS PBR rule will not be extremely onerous and difficult for dispersed and unmanned locations.

TXOGA also stated, "Surely, this reporting can be reduced to a simple GPS position with a one page form maintained in file by the operator stating volume of production, pressures and equipment on site."

The commission concurs that every where use of existing reports is consistent with information necessary to demonstrate compliance that information should be used and not duplicated for these records. Where emissions are generated and vented to atmosphere from separators and storage tanks the emissions can be very similar. However, separators are often operated at a relatively constant level that can reduce some working loss emissions. Please note a focus of this regulation on impacts has a primarily driver in short-term or hourly rates, so the record needs to be able to reflect that short-term emissions will meet the limits. Also, please

note the requirement is to retain a record and not to submit a periodic report.

Owners or operators are currently required to maintain records sufficient to demonstrate compliance with the requirements of a PBR (§106.8). The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The agency recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. For recordkeeping, any documentation that is currently being maintained that provides the same information will be acceptable. In response to this comment and other comments, the commission changes the requirements for E-permitting for Level 1 on the PBR OGS rule to require, at a minimum, only submittal of Core Data and indentifying information (that is, previously claimed historical versions of this section and lease name or well numbers as provided to the Texas Railroad Commission) for existing sites that were not previously registered.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "There are no runtime meters on reboilers and heaters. The subsection (l) Table 7 requirements very unclear and should be clarified by TCEQ. Allow 8760 run hours in lieu of tracking hours for process heaters. Table 7 needs modifications. "Engines and Turbines" should be the listed category label rather than "Combustion Devices" on the previous table entry. Testing requirements for heaters are unclear. See proposed language: "Records of operational monitoring and testing records. For process heaters, boilers, reboilers, and heater treaters that do NOT serve as emission control devices, or where waste gas is utilized in the fuel system, the maximum annual runtime of 8,760-hours may be used to calculate emissions in lieu of runtime tracking. For process heaters, boilers, reboilers, and heater treaters that DO serve as emission control devices, a default destruction efficiency factor of up to 50 percent may be claimed with no additional runtime monitoring or testing. For control efficiency claims greater than 50 percent, records of the hours of operation must be demonstrated by using heater parametric monitoring indicators, including but not limited to, fuel gas usage, flame or fire-eye monitors, process temperature, heater stack temperature, heater firebox pressure, valve position documented by a log book entry, or other valid means of demonstrating heater runtime.

Recordkeeping requirements were not changed in response to this comment. The rule does allow for some increases in emissions without requiring registration. For practical enforceability, the recordkeeping is needed for changes that do not trigger registration requirements. Additionally, replacement facilities are new facilities.

The commission concurs that the record requirement could be misinterpreted to apply where no emissions are expected. To clarify, the commission is moving the record to tanks / vessels where the pressure from which a flash originates is checked weekly. As suggested by the commenter a periodic check of the fluid pressure that is being flashed should be retained.

Since each OGS can be very different with respect to its distance to receptors and property line, this simple accounting procedure is necessary to assess potential emissions and check impact protectiveness.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko comment "Language is unclear as to whether it is requiring measuring fuel usage at each combustion device. If the intent is measurement of fuel at each user, then a size threshold such as 10 mmbtu/hr should be added. This proposed requirement is not protective of the environment. Small process heaters less than 10 mmbtu/hr should be exempt. We run emission calculations for permitting using design capacity duty, rather than measuring fuel usage for each device. Additional arguments: 10 mmbtu/hr level is exempt from NSPS Subpart Dc requirements. The new Boiler/Heater MACT exempts gas fired heaters at area sources. This is overly burdensome for thousands of dispersed oil and gas locations."

The commission added language to clarify fuel usage measurement. The commission added an option for not requiring fuel flow meters. The commission added language to clarify VOC content of fuel. The commission has also updated requirement that operators may assume continuous operations, and limit records to only downtime.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested that the commission "delete the requirement for site inlet and out let gas volume. There is no need for like-kind changes, §106.8 recordkeeping already requires records and is redundant. Please remove from the trucks that pick up the fluids from the tanks. Production reporting requirements and recordkeeping requirements are not necessary. The records are required for only monthly production. Data would be available upon request.

The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The commission recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. For recordkeeping, any documentation that is currently being maintained that provides the same information will be acceptable. The commission does not change the rules in response to this comment to only obtain data upon request by the commission. Submittal of data is required as specified to support reviews or audits of registrations and to ensure practical enforceability. In response to this comment, the commission does not add language to the rules to indicate gas flow rates are not needed for emissions calculations. Based on the commission's experience with review of numerous OGS registrations, gas flow rates are needed for some emissions calculations, such as for GLYCalc emissions calculations for glycol dehydration units, and are not necessary the same gas flow rates that leave or enter a site.

The rule does allow for some increases in emissions without requiring registration. For practical enforceability, the recordkeeping is needed for changes that do not trigger registration requirements.

Encana commented on Table 8 PBR §106.352 and Records showing all replacements and additions, including summary of emission type and quantities.

The commission does not delete replacement and recordkeeping requirements from the new OGS rules in response to this comment. The new OGS rules have more specific replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements, as opposed to the vague recordkeeping requirements of PBR §106.8, are needed for practical enforceability. Recordkeeping, including the recordkeeping for several small changes occurring over specified periods of time, is required for practical enforceability and for demonstrating compliance with the requirements of the OGS rules. The commission does not change the rules in response to this comment. A replacement facility is a new facility and must meet the requirements of the PBR rule, unless otherwise specified. A new facility must meet applicable federal requirements. The commission does not change the rules for recordkeeping requirements in response to this comment.

Encana seeks clarification from TCEQ that only those changes that increase emissions above the thresholds proposed in subsection 106.352(c)(1)(B) of the PBR and subsection (c)(1)(C) the Standard Permit are subject to the recordkeeping requirements."

Recordkeeping requirements were not changed in response to this comment. The

rules do does allow for some increases in emissions without requiring registration. For practical enforceability, the recordkeeping is needed for changes that do not trigger registration requirments. Additionally, replacement facilities are new facilities.

Encana Response: Encana seeks clarification from TCEQ that only those changes that increase emissions above the thresholds proposed in subsection 106.352(c)(1)(B) of the PBR and subsection (c)(1)(C) the Standard Permit are subject to the recordkeeping requirements."

The commission does not change the OGS PBR rule in response to this comment. Recordkeeping, as specified, is required for subsection (c)(1)(B) and (C). The commission moves and addresses the content of subsection (c)(1)(C) under subsection (c)(1)(B). The new OGS rules have more specific replacement and, especially, recordkeeping requirements. More specific recordkeeping requirements, as opposed to the vague recordkeeping requirements of PBR §106.8, are needed for practical enforceability. Recordkeeping, including the recordkeeping for several small changes occurring over specified periods of time, is required for practical enforceability and for demonstrating compliance with the requirements of the OGS rules.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko expressed concerns regarding "Worst-case is not representative of site condition and therefore will grossly overestimate emissions. As stated this requirement could be taken to mean any pressure vessel within the facility and not vessels that have affects on emissions."

The commission concurs that the record requirement could be misinterpreted to apply where no emissions are expected. To clarify the commission moves the record to tanks / vessels where the pressure from which a flash originates is checked weekly. Additionally, the commission considers emissions that are not normal or MSS emissions to be upset or emergency emissions. The commission recognizes that emergency and upset emissions occur at OGS. Therefore, the rules address the use of emergency engines and address the use of flares for upset and emergency conditions. Emergency and upset emissions may need to be included in impacts evaluations under the OGS rules. However, upset or emergency emissions are not authorizable under the OGS rules and are therefore not considered as part of worst-case emissions. The commission considers emissions from a pressure vessel to be emergency or upset emissions if the emissions are not normal or MSS emissions.

The commission added language to the new OGS rules providing the option for claiming 8,760 hr/yr run-time at maximum design capacity for any combustion unit instead of process monitoring. Testing for process heaters can be requested at Region's discretion. The commission does not anticipate requesting testing of heaters that are used as a voluntary control device. The commission clarifies language to indicate applicability to all combustion devices including engines and turbines, and deleted redundant rows from the table. In response to this comment

and other comments including comments about the stringency of PBRs should not necessarily be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed.

TIPRO comments that "operators routinely fix leaks they find using audio, visual or olfactory inspection as part of their normal job duties commented, "The proposed sampling, compliance demonstration, and monitoring, and record keeping requirements discussed are extremely onerous and difficult to implement for the thousands of dispersed unmanned locations. Encana supports the innovative approach to permitting concerning compliance demonstrations.

The commission has changed the rule to allow any documentation that is currently being maintained that provides the same information will be acceptable.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko. "This is overly burdensome for thousands of dispersed oil and gas locations."

The commission added language to clarify fuel usage measurement. The commission added an option for not requiring fuel flow meters. The commission added language to clarify VOC content of fuel. The commission has also updated requirement that operators may assume continuous operations, and limit records

to only downtime.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Burdensome recordkeeping and would reduce the number of these used in the field typically at sour gas locations to avoid H_2S seepage. In addition, 40 CFR 60.633(b)(1) (NSPS KKK) only requires quarterly monitoring."

Any documentation that is currently being maintained that provides the same information will be acceptable. The LDAR programs with instrument monitoring are only required where they are necessary to meet emission limitations. If necessary to meet emission limitations the application of rupture discs under relief valves allows 100 percent fugitive emission reduction credit. Quarterly instrument monitoring may be applied with that credit if preferred.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko requested that the commission "delete the requirement for site inlet and out let gas volume Additionally, leaks create potential safety hazards for the operator on location. There is no environmental benefit by requiring operators to record their walk-through unless a leak is found. As a BMP, operators conduct several inspections on a regular basis for different purposes (safety, maintenance, etc.) or compliance with other regulatory agencies requirements. As long as the operator ensure that fugitive components in the gas service are included in the most appropriate of these inspections, an equivalency with the AVO method can be claimed."

A simple check note with date of a walk through or physical inspection is acceptable, record of found leaks is implied. Only where instrument monitoring is needed to meet the emission limits of the rule of for certified emissions are the records of a monitoring program needed.

Devon commented on Table 8: Monitoring and Records Demonstrations Minor Changes Ft Equipment Replacements: "The requirement to keep records of like-kind replacements should be struck from the rule, as like-kind replacements have no impact on emissions. Similarly, the requirement to keep records of "minor" changes at a site is not warranted, since any change that increases the potential to emit will require the site to re-register."

The commission has changed the rule language in response to this comment. Any LDAR program that a site implements is voluntary, and if implemented must follow the requirements of the PBR rule, unless otherwise specified. A new engine must meet applicable federal requirements. Recordkeeping requirements were not changed in response to this comment. The rule does allow for some increases in emissions without requiring registration. For practical enforceability, the recordkeeping is needed for changes that do not trigger registration requirements.

Encana commented on Table 8 PBR §106.352 and Standard Permit- Category - Minor changes "Records showing all replacements and additions, including summary of emission type and quantities. Encana Response: Encana seeks clarification from TCEQ that only those changes that increase emissions above the thresholds proposed in subsection 106.352(c)(1)(B) of the

PBR and subsection (c)(1)(C) the Standard Permit are subject to the recordkeeping requirements."

Recordkeeping requirements were not changed in response to this comment. The rule does allow for some increases in emissions without requiring registration. For practical enforceability, the recordkeeping is needed for changes that do not trigger registration. Additionally, replacement facilities are new facilities.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko expressed concerns regarding "Worst-case is not representative of site condition and therefore will grossly overestimate emissions. As stated this requirement could be taken to mean any pressure vessel within the facility and not vessels that have affects on emissions."

We concur that the record requirement could be misinterpreted to apply where no emissions are expected. To clarify we are moving the record to tanks / vessels where the pressure from which a flash originates is checked weekly. As suggested by the commenter a periodic check of the fluid pressure that is being flashed should be retained.

TIPRO commented that, "The requirement "Records showing all replacements and additions that result in an increase of more than 1 tpy VOC, 5 tpy NO_X, 0.01 tpy benzene, and 0.05 tpy H_2S, including summary of emission type and quantities" is unrealistic and has no significant impact on emissions. There is no environmental benefit to be gained compared to the burden of tracking all minor valve and fitting change at an oil and gas site."

Changes, especially new equipment are modifications requiring evaluation and normally always requiring authorization. The commission is allowing some adjustment with appropriate minimum potential for impact concern in all cases to skip or delay the authorization process. Every site should be aware of their emission potential and equipment at every site. The commission is not requiring leak no leak monitoring as described in the fugitive documents in AP-42 to account for fugitive emissions. Simple counts with the less conservative oil and gas factors are allowed and are easy to track. Since each OGS can be very different with respect to its distance to receptors and property line, this simple accounting procedure is necessary to assess potential emissions and check impact protectiveness.

Devon commented on Table 8: Monitoring and Records Demonstrations Equipment Specifications. "Process units, tanks, vapor recovery units, flares, thermal oxidizers, and reboiler control devices: This section requires records be kept for volumes, pressures, design specifications, equipment sizing, etc. Devon recommends that the section is more specifically phrased toward keeping records directly related to air emissions, with recommended language as follows: "Emissions control equipment specifications, volumes and pressures of process streams, and pertinent compositions used for emissions calculations shall be available at the nearest manned facility or at the owner/operator company headquarters.""

The commission concurs and has adjusted the language for tanks and vessels venting to the atmosphere to be in line with assessing the emission.

In response to this comment and other comments, the commission changes language in the OGS PBR rule to indicate all fugitive components need to be physically inspected for leaks onunder the LDAR program. The rule will include a quarterly physical inspection as part of BMP, and the appropriate records for the physical inspection. Any other record that shows compliance with the rules will suffice.

The details provided in this PBR are designed to clarify the appropriate monitoring methods, sampling, and the records required to meet that general requirement as outlined in §106.8. The commission recognizes that there may be monitoring, sampling, or recordkeeping methods that were overlooked and that are equivalent to those specified. For recordkeeping, any documentation that is currently being maintained that provides the same information will be acceptable. The commission does not change the rules in response to this comment to only obtain data upon request by the commission. Submittal of data is required as specified to support reviews or audits of registrations and to ensure practical enforceability. In response to this comment, the commission does not add language to the rules to indicate gas flow rates are not needed for emissions calculations. Based on the commission's experience with review of numerous OGS

registrations, gas flow rates are needed for some emissions calculations, such as for GLYCalc emissions calculations for glycol dehydration units, and are not necessary the same gas flow rates that leave or enter a site.

EDF commented that the TCEQ should clarify in Table 8 that "for storage tank loading, the maximum short-term emission rate should include a rigorous calculation of flash gas emissions."

No changes to the rule are required based on this comment. The commission agrees with this comment and will ensure that any emissions quantification guidance establishes established and clearly identifies the need for short-term emissions, including potential flashing, which occurs from truck loading, storage tanks, or other sources, if appropriate.

Sierra Club members "would like the proposed permits to require signage at each OGS stating the name of the owners and operators, listing all pertinent facility registration numbers and permits, and providing contact phone numbers for regulatory agencies. This information is critical for citizens. Currently, it is often very difficult for citizens working or living nearing OGS to determine who owns or operates the site, particularly when the site is un-manned."

The commission respectfully declines to revise the rule based on this comment. The public can access information about a certain site or location by contacting

their local region or by accessing the TCEQ website, which is updated each day for pending and completed registrations and applications. Additionally, the public can access the remote document server where many agency generated documents, including technical reviews and associated letters for registrations, are available within days of completion.

S*ampling, Monitoring*

Encana commented on Table 8 PBR §106.352 and Standard Permit - Category -Control Devices-Condensers "Basic monitoring is continuous monitoring and recording of the temperature of the waste gas exhaust, Encana Response: This requirement does not consider small, remote facilities that have no electricity and are unmanned. Operators should be given the option to record the temperature on a monthly basis. Encana proposes that the language for monitoring and recording temperature for condensers be replaced with the following: "Basic monitoring is measuring and recording the condenser outlet temperature at least 1 day, each month during daylight hours. Recording of the condenser outlet temperature is not required if the uncondensed vapors are burned in a combustion device or recycled back into the process.""

Encana commented that in Table 7 PBR §106.352 and Standard Permit - Category -- Condensers – "Proper monitoring and sampling ports must be installed in the vent stream before and after the condenser. Encana Response: Encana agrees that monitoring condenser outlet temperature is valid parametric, monitoring; however, it is unnecessary to require sampling ports when there is no clear testing requirement. The requirement for sampling ports should only be for condensers where compliance testing is required."

The condenser sampling requirements are being removed and being replaced with the glycol dehydrator monitoring requirements in Table 8, no sampling ports are required for the PBR.

The TCEQ changes the rule in response to this comment for clarity and resolution. After re-evaluation, the commission deletes deleted the testing requirements for testing after maintenance of engines. The commission determines determined that normally scheduled semi-annual or biennial testing of engines will be sufficient for demonstration of compliance for engines addressing testing after maintenance.

El Paso commented requested that the commission consider "revising the requirement to test "any turbine" to "any turbine (excluding microturbines)." El Paso employs small Capstone microturbines at some facilities that do not lend themselves well to emissions testing due to their exhaust system design. These microturbines have the potential to emit on, the order of less than 1 tpy of any pollutant. Alternatively, please consider a deminimis level for turbines (e.g., "Any turbine> 1 MW)."

The TCEQ does not change the rules has not changed the proposal in response to this comment. Due to high exhaust flow and pollutant concentrations, turbines can represent large emission sources even at 1 MW. The commission TCEQ routinely works with permit holders who cannot meet aspects of EPA test methods

such as Test Method 1 to design a testing protocol that achieves a valid test. It is the commission's TCEQ's intent that small turbines such as the Capstones be tested according to the procedures of EPA Test Methods as best possible. Engines commonly have the small issues as these smaller turbines and the TCEQ. The commission routinely works with has routinely worked with the testing companies company to come up with a valid testing methodology.

SWEPI comment that the new Chapter 106 states that "The new PBR would require continuous measurement of condenser outlet gas temperature . . . at an estimated cost of about $4,000.00"; however, this appears to conflict with the proposed Chapter 106 Table 8 - Control Devices - Condensers which states "Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits." If this is not in conflict, then clarifications as to requirements for claimed efficiencies should be clearly stated in Table 8. The company request clarity or resolution of the continuous condenser outlet gas temperature requirement referenced in the PBR preamble with the proposed provisions in Table 8, Control Devices, Condensers, which state "Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits."

The commission changes the rule in response to this comment for clarity and resolution. All monitoring and controls are voluntary in the final OGS PBR. If a control is needed to meet the emission impacts or limitations of the PBR, then the once weekly monitoring of the temperature of air condenser exhaust along with other parameters as listed in Table 8, Process Units, Glycol Dehydration Units

apply. Continuous temperature monitoring is not required over the once weekly monitoring of air condenser exhaust temperature.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko requested clarification "Why is testing required when these "events" reduce emissions, is this in addition to quarterly testing? We need clarification as to what constitutes "major" component replacement."

After re-evaluation, the commission deletes the requirements for testing after maintenance of engines. The commission determines that normally scheduled semi-annual or biennial testing of engines will be sufficient for demonstration of compliance after maintenance.

Targa commented on fugitive monitoring requirements. "Fugitive monitoring will be extremely difficult to implement due to the large number of sites requiring monitoring. There are numerous issues with this portion of the proposed rule: The rules should properly define which process streams require fugitive emissions controls. The proposed language in the PBR and Standard Permit does not define which process streams are subject to controls. There needs to be an exemption for minimum weight percent VOC content of the stream. There is no reason to monitor residue gas which is almost entirely methane. The precedent for defining which process streams require controls for VOC is found in 40 CFR 60.632(f): "For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can never be reasonably expected to exceed 10.0 percent by weight." The proposed rule should also include a section on exemptions from monitoring. For example, exemptions from monitoring based on configurations, component types like check valves, seal systems, vacuum service, less than two inches, instrumentation systems, sampling systems, etc. These lists of exemptions are standard in all EPA and TCEQ regulations for fugitive emissions and are startlingly absent in the proposed rule. In addition, Targa would need more clarification on which component types are required to be monitored under Method 21. For example, in reading §106.352(e)(7), it appears that all fugitive components and instrumentation in gas or liquid service is subject to Method 21 monitoring. However, the leak definition in §106.352(e)(7)(C) only provides for valves, connectors, pumps, compressors, and agitator seals. Targa finds these component types requiring monitoring more stringent and aggressive than the Federal LDAR NSPS KKK monitoring component types required for gas plants. The lack of available contractors to complete the work will make initial implementation very difficult. Most companies contract out their leak detection programs to third parties. The cost to implement a fugitive monitoring program is considerable. It is a very labor intensive process. Each site would have to be manually tagged, monitored, and logged into an electronic system for tracking and reporting. Compressor stations are numerous and spread out across a particular gathering area. In Targa's North Texas system alone, it can take several hours to reach the farthest compressor station. Further, certain Right-of-Way agreements add complexity to site access. All of Targa's compressor stations are unmanned which means third parties would have to be hosted while doing their monitoring."

Targa also recommended "more emphasis on required AVO inspections and elimination of required monitoring using Method 21 or the alternative work practices. This would allow sites to use the incentive program in 30 TAC Chapter 101 and increase the use of IR camera's in the oil and gas industry."

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that fugitive monitoring is "overly burdensome for remote OGS. It is not reasonable to require leak testing within eight hours at largely unmanned facilities. This would cost industry millions for monitoring hundreds of thousands of oil and gas facilities. Furthermore, there are not enough monitoring companies in the country to do this work. This requirement is largely covered by DOT regulations already. Remove this requirement. Alternatively, revise this language as follows: "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 eight hours, 15 days of the components being returned to service. Alternatively, the new components shall be tested for leaks using a soap solution within eight hours of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance.""

SWEPI commented that, "Since the monitoring program in the proposed PBR 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 an LDAR program, the applicability is limited and should be considered as duplicative and unnecessary. The adoption of Federal GHG Subpart W provisions also supports this as duplicative and unnecessary."

El Paso commented that, "the imposition of biennial reference method testing in addition to quarterly portable analyzer testing seems overly burdensome.

The commission has changed the required fugitive program to only a quarterly physical inspection. At any site which implements a voluntary LDAR program, or must comply with any other state (30 TAC Chapter 115) or federal (NSPS 40 CFR Part 60, Subparts KKK, or GHG or Subpart W) may use that program instead of the physical inspection.

Encana commented on Table 8 PBR §106.352 and Standard Permit- Category - Site LDAR Program - (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. Encana Response: Operators fix leaks they find using audio, visual or olfactory inspections, Operators fix these leaks as part of their job duties because leaks are a loss of product and therefore a loss of revenue. Additionally, leaks create potential safety hazards for the operator on location. There is no additional environmental benefit by requiring operators to record their walk-through unless a leak is found. A requirement to record a walk-through where no leaks are found only provides additional enforcement risk to operators over recordkeeping. The requirement to record a weekly walk-through should be stricken from the proposed regulation and recordkeeping should only involve leaking components."

In response to this comment and other comments, the commission changes language in the OGS PBR rule. The commission re-evaluated what is required for fugitive monitoring under the OGS PBR, to indicate all fugitive components need to be physically inspected for leaks on a quarterly basis. The commission intentionally avoids the use of AVO as AVO is actually LDAR. Physical inspection

for leaks is not part of LDAR. Additionally, the commission believes it is reasonable to assume that OGS will not want to lose substantial amounts of product. As such, the commission determines that all fugitive components need to be physically inspected quarterly for leaks. The recordkeeping requirements for physical inspections for leaks are not detailed records, nor as stringent as recordkeeping requirements for LDAR. The PBR rule also allows for the use of voluntary LDAR or required federal LDAR (such as LDAR for 40 CFR 60 NSPS KKK or GHG Subpart W); weekly physical inspections are required in tandem with LDAR. The TCEQ changed the frequency for monitoring from quarterly to semiannually. After consideration, the commission changed language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufacturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing was added as an option. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments. Instrument monitoring at sites is now only required where necessary to meet emission limitations. The commission changes the rule has adjusted the requirements to allow soap bubble testing within eight hours to look for leaks in lieu of instrument monitoring and to increase the time frame for instrument

monitoring to 15 days. Additionally, gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service is an option in lieu of soap bubble testing and instrument testing. Instrument monitoring at sites is now only required where necessary to meet emission limitations. The use of a camera is an option.

El Paso employs small Capstone microturbines at some facilities that do not lend themselves well to emissions testing due to their exhaust system design. These microturbines have the potential to emit on, the order of less than 1 tpy of any pollutant. Alternatively, please consider a deminimis level for turbines (e.g., "Any turbine> 1 MW)."

The commission has not changed the rule in response to this comment. All combustion devices must be considered for compliance demonstration purpose of criteria pollutants.

Encana commented on Table 7 PBR §106.352 and Standard Permit - Category - Combustion Devices Biennial Testing. "Any engine greater than 500 hp or any turbine - After biennial testing, any engine retested under the above requirements shall resume periodic evaluations within the next two calendar quarters. Encana Response: The language above should be replaced with the following: "The biennial Compliance Test will be performed in lieu of the semi-annual Performance Test required during the same semi-annual period In which the Compliance Test is performed.""

This comment is unclear to the commission. However, the commission rewords has reworded the language section in response to other comments.

Cirrus commented that, "The proposed PBR and Standard Permit require that evaluations of engine emissions performance be conducted quarterly by measuring the NO_X, CO, and oxygen content of the exhaust. It also requires that these evaluations be conducted within 14 days of events such as engine maintenance or overhaul, oxygen sensor replacement, etc. The current PBR requires that these evaluations be conducted within 7 days of such maintenance events. Where engines are subject to 117, these evaluations are required within 14 days. Please clarify when these evaluations are required and the reason for the timing."

The commission changed quarterly testing to semiannual testing for engines in response to comments. After re-evaluation, the commission deleted the testing requirements for testing after maintenance. The commission determined that normally scheduled semi-annual or biennial testing will be sufficient for addressing testing after maintenance.

TIPRO commented that" performing stack test for VOCs is an unnecessary additional expense to an already expensive compliance stack test. VOC emission rates are typically very low from engines and boilers firing on natural gas. Manufacturers' specifications or AP-42 factors provide conservatively high emissions estimates for emission estimation purposes."

The commission removes the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "Portable analyzers are not able to monitor VOC emissions. There is no way to document compliance with VOC standards. VOC standards should be removed from rule. VOC limits should be removed for engines <500 hp as there is no means of compliance demonstration and portable analyzers do not measure VOC which would require use of reference method testing for compliance demonstration."

TPA commented that the proposed PBR "contains unduly onerous testing requirements. The proposed PBR's testing requirements would go beyond the sort of requirements that should be included in a PBR. The problem is especially pronounced with respect to engines: once EPA imposes the upcoming engine rules, most engines will be subject to federal requirements regarding testing in any event. The state's PBR should not impose duplicative or inconsistent testing requirements on those same engines. Examples of the proposed testing requirements that TPA believes are unnecessary and too burdensome include the site-specific sampling requirements under worst-case scenarios and the portable testing methods proposed for engines."

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated that "there needs to be a standardized compliance determination. The standard should reference a maximum achievable site load."

TAEP commented that, "Quarterly engine testing will overload the current availability of qualified and certified emission testing companies, if we are to test every 0&G related engine larger than 100 HP. This quarterly test requirement goes beyond Federal emissions testing rules which do not require testing of engines smaller than 500 HP except in areas of nonattainment."

SWEPI commented that, "The periodic sampling for engines should consider CTM-034 testing should be allowed to be conducted by the operator. This can then be complemented by complete 3rd party stack testing once every 2 years if quarterly performance consistently meets permitted emissions requirements. Also, engines subject to NSPS JJJJ or ZZZZ are tested annually by a third party. Therefore, it would be highly advantageous to use an alternating equivalency schedule for the same engine at a particular location using the same fuel with catalyst package and maintenance schedule. Additionally, the requirement to test engine emissions after an 02 sensor replacement, major maintenance, or catalyst change-out should be extended to 4 weeks instead of the proposed 2 weeks. Since equipment performance is already monitored frequently, the extended deadline would help ensure that no undue burden is placed on staff."

SWEPI commented that, "The requirements for formaldehyde and VOC listed in the new 30 TAC 116 do not align with the requirements in the 30 TAC §106.352. El Paso requested consideration of "revising the requirement to test "any turbine" to "any turbine (excluding microturbines)." El Paso employs small Capstone microturbines at some facilities that do not lend themselves well to emissions testing due to their exhaust system design. These microturbines have the potential to emit on, the order of less than 1 tpy of any pollutant. Alternatively, please consider a *de minimis* level for turbines (e.g., "Any turbine> 1 MW)."

The TCEQ has not changed the proposal in response to this comment. Due to high exhaust flow and pollutant concentrations, turbines can represent large emission sources even at 1 MW. The TCEQ routinely works with permit holders who cannot meet aspects of EPA test methods such as Test Method 1 to design a testing protocol that achieves a valid test. It is the TCEQ's intent that small turbines such as the Capstones be tested according to the procedures of EPA Test Methods as best possible. Engines commonly have the small issues as these smaller turbines and the TCEQ has routinely worked with the testing company to come up with a valid methodology.

Devon commented that more specifically, the 30 TAC 116 states that "the new standard permit would require testing for emissions of total VOCs and formaldehyde from engines" whereas the 30 TAC §106.352 states that "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." Please note that standard methods and calibration standards for formaldehyde are not well developed or widely used at this time and consequently require highly specialized and costly equipment, such as Fourier Transform Infrared (FTIR) spectrometers."

Exterran commented that, "Historical engine tests are not always available due to transporting engine from another state to Texas or prior owner/operator did not maintain tests. Clarify that records are only required for the time the engine has operated on the oil and gas site within the past 5 years. If most recent demonstration test is not found when placed upon the site, allow for a retest to demonstrate compliance prior to registration. Recommendation: Amend this provision to read as follows: Records of Reference Method performance testing, must remain with each specific engine for a maximum of 5 years for each site beginning with the initial performance test after construction. Alternatively, if a record of a previous EPA reference method test performed less than 2 yrs ago at a different site is available, it may be used for compliance demonstration at a new site until the next required test is conducted."

Encana commented that Table 7 PER §106.352 and Standard Permit - Category Engines and Turbines "initial Sampling of (I) Any engine greater than 500 hp; (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, CO, VOC, and oxygen). Encana Response: Stack testing of VOCs is an unnecessary additional expense to an already expensive compliance stack test. VOC emission rates are typically very low from engines and boilers firing on natural gas, Manufacturer's specifications or AP-42 will provide conservatively high emission estimates that will adequately provide emission estimates. The requirement to compliance stack test for VOCs should be removed."

El Paso commented that, "Although suggested by the language under "Periodic Evaluation", the rule should state clearly that the periodic evaluations are limited to engines larger than 500 HP or other fired devices larger than 40 MMBtu/hr heat input. Further, El Paso suggests that quarterly emission tests are unnecessary. El Paso suggests that annual evaluations are sufficient."

Encana commented that Table 7 PBR §106.352 and Standard Permit - Category - Engines, Periodic Evaluation " (A) Conduct evaluations of each engine performance every calendar quarter after initial compliance testing by measuring the NO_X, CO, and oxygen content of the exhaust. Encana Response: An effective maintenance program will keep engines in continual compliance. To reduce economic impact to operators, when four consecutive quarterly tests show the engine in compliance with its hourly permit limits, the testing frequency may be reduced to semi-annual testing. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing, Upon any demonstration of non-compliance with hourly permit limits, the testing frequency shall revert back to quarterly, The ability to revert to a semi-annual /annual test rotation is a significant savings to operators while maintaining and demonstrating compliance at the same time. Please see the table above for detailed recommendations of testing frequency for different size and location of engines."

Weisman Engineering commented that, "The requirement for periodic evaluation of engines over 500 hp as shown in table 7 requires quarterly testing with portable analyzers for NO_X, CO, and oxygen throughout the State of Texas. This is not consistent with the testing required in nonattainment counties in the DFW area, which only require stain tube testing quarterly. Since the portable analyzer testing is not required to be submitted to the TCEQ, and all data in the preamble to the referenced rule is for engines over 1000 hp, it is not consistent to require testing to this level. Stain tube testing is reliable to determine whether an engine is meeting its emission requirements and it is recommended that stain tube testing of engines be permitted up to 1000 hp. The new NSPS standard referenced in the preamble does not require periodic testing of engines and no explanation is given as to why TCEQ is proposing to require it. TCEQ foes not have data on engines less than 240 hp since these have never been permitted. The audit referenced on page 33 of the preamble would only contain data on engines less that 240 hp that were at sites which also contained engines more than 240 hp. Since there are no previous requirements for periodic testing and since it is not required by EPA and there is no data about these engines, except that it will cost $2,000 a year to test them, it is recommended that engines less than 240 hp not be periodically tested."

TIPRO commented that, "There are not enough testing companies to test every engine in Texas larger than 100 HP every quarter and that EPA does not require quarterly testing for either NSPS or NESHPS. TIPRO commented that an effective maintenance program will keep engines in continual compliance. TIPRO recommended using an approach from Oklahoma air permitting to construct oil and gas facilities. This language comes for their regulations: "Conduct evaluations of each engine performance every calendar quarter after initial compliance testing by measuring the NO_X, CO, and oxygen 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 3-month (quarterly) period. When four consecutive quarterly tests show the engine in compliance with its hourly permit limits, the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test. Upon any showing of non-compliance with hourly permit limits, the testing frequency shall revert back to quarterly."

TAEP commented orally that, "Quarterly testing of engines will be burdensome and met with personnel and testing constraints." They followed in writing that, "Quarterly engine testing will overload the current availability of qualified and certified emission testing companies, if we are to test every O&G related engine larger than 100 HP. This quarterly test requirement goes beyond Federal emissions testing rules which do not require testing of engines smaller than 500 hp except in areas of nonattainment." The suggested corrections included the following: "Require quarterly testing only in areas of nonattainment. For areas of attainment, require testing only for engines larger than 500 hp. Use a testing schedule for successful test which reduces the requirement over time from quarterly to semi-annual to annual."

Exterran commented that the rule "Currently requires another evaluation of engine performance after engine maintenance such as "major component replacement, overhaul, oxygen sensor replacement or catalyst replacement." Recommendation: Clarify or delete the general terms "engine maintenance" and "major component replacement, overhaul" and tie testing requirement to actions that could reasonably be expected to increase emissions. Also, request clarification that such testing could satisfy quarterly testing requirement as well."

Devon commented on Table 7 Sampling and Demonstrations Engines - Periodic evaluation. Devon commented, "This section requires portable analyzer testing every calendar quarter, which goes beyond federal NSPS and NESHAP requirements and is not required in §106.512, which remains as an applicable PBR for engines in other industries. Furthermore, the quarterly testing requirements here are consistent with the Chapter 117 nonattainment rules, in 30 TAC §117.8140(b), and are not justified or warranted to be applied to engines statewide. Quarterly testing is costly and economically unwarranted for smaller engines (less than 500 hp). Devon recommends using the framework established in §106.512 to consistently regulate industries in Texas. In the event quarterly testing remains as a requirement, Devon suggests extending the test frequency in a phased approach based on the results of previous tests. For example, after four consecutive quarters of testing that indicates the engine is in compliance, extend the frequency to annual testing. Finally, there are not enough testing companies in Texas to conduct portable analyzer testing on a quarterly basis statewide. Portable analyzer testing is time consuming, onerous, and would result in significant cost increases on operators due to testing costs and additional manpower needs. Alternative test methods, such as stain tube or other operator defined methods should be allowed for quarterly emission evaluations."

Encana commented on Table 7 PER §106.352 and Standard Permit- Category - Engines- Periodic Evaluation. "(C) 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 2 weeks, Encana Response: This requirement appears to be adopted from 30 TAC §117.8140(b) which is applicable to NO_X sources located in nonattainment and early action counties. Extending its applicability to sources located in attainment areas and unmanned rural areas would be extremely burdensome and not provide additional environmental benefit. However, Encana believes that the requirement to conduct performance tests after maintenance should remain applicable to those engines subject to 30 TAC subchapter 117."

SWEPI commented "(C) 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 2 weeks, Encana Response: This requirement appears to be adopted from 30 TAC §117.8140(b) which is applicable to NO_X sources located in nonattainment and early action counties. Extending its applicability to sources located in attainment areas and unmanned rural areas would be extremely burdensome and not provide additional environmental benefit. However, Encana believes that the requirement to conduct performance tests after maintenance should remain applicable to those engines subject to 30 TAC subchapter 117."

ETC commented that, "The proposed PBR's testing requirements will go beyond the sort of requirements that should be included in a PBR is especially pronounced with respect to engines: once EPA imposes the upcoming engine rules, nearly all engines will be subject to the federal requirements regarding testing. The state's PBR should not impose duplicative or inconsistent testing requirements on those same engines. Examples of the proposed testing requirements that ETC believes are unnecessary and too burdensome include the site-specific sampling requirements and the portable testing methods proposed for engines."

The commission changes the rule in response to these comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition of those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site. Additionally, testing of similar groups of engines is allowed. They must undergo testing once every 4 years as long as half of the group is tested every 2 years. The commission deletes the requirement for formaldehyde and VOC testing and determines that CO testing is an acceptable surrogate for formaldehyde and VOC testing for engines. The testing run duration is changed to match the period of the EPA test method. The initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring and the commission does not change the frequency for monitoring from quarterly to semiannually. Quarterly testing is no more stringent than what is required at Title V sites. The commission does not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512. After consideration, the commission changes language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufacturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally,

stain tube testing is added as an option. This represents savings of thousands of dollars a year for each engine that can take advantage of it. The commission does not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments. The commission would only be able to change rule language for counties subject to 30 TAC Chapter 117 in rulemaking for that chapter. Table 6 requires a minimum load of 50 percent for initial and biennial testing. The commission changes language to address situations were an engine is idle, but the requirement to operate at 50 percent or greater load is not changed in response to this comment. The commission believes that a 50 percent load is achievable for all engines subject to testing and does not impose any burden on permit holders. Periodic evaluation does not require any specific load.

SWEPI commented on "demonstration of best management practices by a maintenance program and records management, such as glycol solvent maintenance, glow plug maintenance, corrosion control, and burner maintenance, should provide adequate control to demonstrate rated emissions performance. The addition of a temperature indicator (TI) and recorder on the glycol condenser offers no added emissions controls benefits if the condenser system can be verified as closed with P&ID's

The commission has revised both the best management practices and the glycol dehydration unit requirements. The commission is asking for records to be kept of parameters needed to accurately estimate emissions. In addition to the parameters asked for being necessary for emissions calculations, they should be routinely looked at by site operators/engineers to check the units are performing well. The following describes what is in the rule regarding records and monitoring. Glycol Dehydrator language has been changed to just records to include dry gas flow rate, absorber pressure and temperature, any reboiler stripping gas flow rate, and condenser outlet temperature, glycol type and circulation rate recorded weekly. VRU, flare or thermal oxidizer or reboiler fire box used for control must comply with the monitoring and recordkeeping for those devices. Where all emissions from the flash tank and the reboiler or reboiler condenser vent are directed to a VRU, Flare or Thermal Oxidizer designed to be on-line at all times the glycol dehydrator is in operation the control system monitoring for the glycol dehydrator is not required.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that the "Language on worst-case period is very limiting. Stack testing will have to be performed during the summer, and many dehydration units are out of service in the summer. We propose to remove "worst-case period" language from the rule. Onerous cost for extended analysis pre and post condenser to demonstrate efficiencies. Consider the following: for efficiency claims greater than 90 percent, you need to meet control, recordkeeping, and monitoring requirements of NESHAP HH. They recommended rule changes: "Effectiveness may require sampling or monitoring upon request by the TCEQ or local programs and is required in all cases where greater than 90 percent is claimed. Proper monitoring and sampling ports must be installed in the vent stream before and after the condenser. 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. In lieu of stack testing, efficiency claims greater than 90 percent shall meet the control, recordkeeping, and monitoring requirements of NESHAP Subpart HH.""

The commission agrees that proper maintenance of engines is an important part of ensuring compliance. The commission believes that emissions performance will not be degraded due to proper maintenance and that it is in the best interest of OGS to perform proper maintained to reduce overall long-term costs and to maintain efficiency. The commission decides has decided that, in general, engine testing along with proper maintenance is needed to ensure compliance. Also, in addition to emissions limitations, 40 CFR 60 NSPS and 40 CFR 63 MACT standards also specify maintenance requirements as part of ensuring compliance. In response to several comments including this comment, the commission deleted deletes requirements of engines < 500 hp. The commission changed quarterly monitoring to semi-annual monitoring as explained elsewhere in response to comments. The commission determined that the semi-annual testing is needed with no exemptions, as explained elsewhere. The potential cost of the semi-annual testing has been greatly reduced as explained elsewhere. The commission changes

the rule in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. This represents savings of thousands of dollars a year for each engine that can take advantage of it. The commission deletes the requirement for formaldehyde testing and determines that CO testing is an acceptable surrogate for formaldehyde testing for engines. The testing run duration is changed to match the period of the EPA test method. The commission removes the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The commission does not change the frequency for monitoring from quarterly to semiannually. Quarterly testing is no more stringent than what is required at Title V sites. After consideration, the commission changes language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufacturer's instructions, operator-defined test methods, or NELAC accredited test methods. The commission does not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment

areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments. The commission determines that the changes to testing requirements are sufficient, and therefore the commission did not change the rule to allow for the future frequency for future testing to be based on past testing results.

Encana commented on Table 7 PBR §106.352 and Standard Permit - Category - Oxidation or Combustion Control Device - Thermal Oxidizers. "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, Encana Response: The requirement for two parametric monitoring devices is unnecessary, overly burdensome and goes beyond strict federal requirements for the oil and gas industry. Combustion zone temperature is the easiest parametric device to maintain and operate and is more meaningful over oxygen monitoring. 40 CFR Part 63, Subpart HH - National Emission Standards for Hazardous Air Pollutants From Oil and Gas Production Facilities only requires temperature monitoring (§63.773(d)(i)(A). Oxygen monitoring is duplicative, unnecessary and the monitoring QA/QC component is impractical to implement in remote locations."

SWEPI commented on Sampling General "required sampling includes three one hour test runs.

While this is a well established protocol for continuous emissions monitoring from engines, heaters, and boilers, the accuracy, precision, and associated quality assurance is not well established for processes that may have intermittent emissions or variable cycle times." If this condition is combined with the condition where an already low VOC value is used for the vent before the control device, then there can be opportunity for great variability in removal efficiencies that may not be representative of overall continuous performance, Temperature cycling may also cause some pressure swings in and around the glycol condenser. This may contribute to non-representative samples. For these reasons sampling process points on glycol systems does not offer any advantages over use of models such as GRI's GlyCalc. We believe emissions sampling of the glycol reboiler vent stack, when not in a closed loop configuration, offers adequate emissions assurance along with demonstration of best management practices (BMP)."

The use of continuous emissions monitoring is an option for periodic evaluation of engines, not a requirement. The commission agrees that the validity of three one hour test runs for testing of sources, including engines and other sources typically operating steady-state, has been well established and that the applicable parameters for periodic evaluation of engines is dependent on engines testing results. The commission has clarified that control monitoring is only necessary when control is needed to meet emission limitations or certify emissions with control. The more extensive parametric monitoring is only applicable where the highest effectiveness of the control is claimed. The commission believes this monitoring is appropriate if company needs to make this claim.

The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any recordkeeping and additional cost to industry. Additionally, the commission does not necessarily consider a glycol unit reboiler firebox subject to 40 CFR 63 MACT HH to also be a thermal oxidizer.

Exterran recommended only "Sampling General (B) Recommendation: Amend this section to require "three one-hour thirty (30) minute test runs" for Reference Method tests only."

The commission concurs with this comment and changes the rule. The TCEQ has changed the proposal to reference EPA reference methods and the test duration referenced within the method.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "Liquid analysis of produced water requires a pressurized water sample to demonstrate compliance which serves no purpose. There is no benefit for most samples to be in a c10+ format. Exempt tanks at sites that make no liquid hydrocarbon are produced from the production stream. Exempt sites that have a VRU or flare to handle tanks vapors. They propose revised rule language of "Maintain composition records at appropriate points within the process as needed for emissions calculations. 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. 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.""

SWEPI commented that, "The new PBR would require the sampling of emission gas streams with a cost estimated at $800 to $5,000 per sample. Although this estimate is reasonable, this does not include travel to remote areas, man lifts, associated staff time, installation of ports, and safety reviews for new activities. When these factors are included, costs can exceed $10,000 per sample. Similarly, the new PBR total cost of testing VOC for engines and turbines is estimated from about $500-$2,000 per test. This also does not include travel to remote areas, man lifts, associated staff time, installation of ports, and safety reviews for new activities."

TAEP commented that, "Site-specific gas and liquid analysis will be an un-necessary burden in cost and time. It is unlikely that available lab resources exist now or in the near term years to accommodate the volume of sample analysis anticipated by rule requirement. They recommended that the commission allow the use of representative reporting field level data; Require "site-specific" data only in critical emission sources; Require "site-specific" data only where estimated emissions are close to thresholds."

Encana encourages solutions such as emission factor development or representative sampling.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that the "TCEQ should allow for the use of representative gas and liquid analysis as opposed to site specific analysis so long as certain criteria are met for characterizing the analysis as representative. The following items could be used for defining whether an analysis is representative or not: Production type: grouping of fields or wells within fields on the basis of gas or oil production. Same or similar producing reservoirs: grouping of fields on the basis of reservoir types such as tight sands, coal bed methane, conventional sands, and shale gas. Different named formations/reservoirs with the same classification, such as tight sands, with less than 2,000 vertical feet between the formation tops could be grouped. Similar ranges of pressure and temperature for the initial phase separation of production from the wells. Although the pressure can vary quite widely, for even the same producing horizon/formation, dependent on "well-head" compression the general collection and gathering system pressure in the fields being grouped should be similar. Similar fluid compositions such as oil with associated hydrocarbon gas, primary hydrocarbon gas production with hydrocarbon liquids that separate at field separators, "dry" gas with no appreciable (<2 barrels per MMSCF) hydrocarbon liquid production. Similar API gravity could be used for demonstration purposes. Similar production arrangements, surface equipment, and operational characteristics/practices: Fields to be grouped should employ similar production approaches such as well-site phase separation with equipment located on or near individual well sites or small groups of wells, multi-phase flow to central separation and production facilities (such as central tank batteries). Also they could be grouped by similar treatment of the gas or liquids."

TIPRO commented that the "proposed requirement for site-specific samples will cause immediate non-compliance across the State as there is a lack of industry personnel, contractors, equipment and laboratories to handling the massive increase in sampling. Representative samples are sufficient for PBR registrations and insignificant emission sources."

Encana commented that, "Field wide averages are adequate for estimating emissions. Permit reviewers can determine whether site specific samples are necessary based on a minimum data set of 3 samples per field. Another approach that has been allowed by the Agency for the past year is the use of analog samples that represent production form (sic from) the same formation, field and depth. Encana agrees with the TCEQ statement that the surrogate sample should be the most conservative of the represented sites to demonstrate worst-case scenario."

Devon commented on Table 7 Sampling and Demonstrations of Compliance, LDAR Verify Composition of Materials, all site specific gas or liquid analyses. "This section includes language that requires extended gas chromatograph (GC) analyses be obtained for certain gas and liquid streams, and subsequently used for compliance demonstrations. This includes: (D)Tanks for liquids and vapors; and (E) Produced water or brine/salt water at the inlet prior to storage. TCEQ-approved methods for calculating emissions from tanks do not require site specific sampling be obtained for storage tank liquid and vapor, as well as produced water. For the emissions calculations, a pressurized sample at the separator is needed along with the API gravity and RVP of the sales oil. The composition of the sales oil is not needed. Additionally, the composition of the tank vapor does not need to be measured, as this is calculated in the model. The emissions from produced water tanks are minimal, thus sampling the water for hydrocarbons has no cost-benefit justification. Devon has typically used conservative oil carryover estimates as a basis for calculating water tank emissions. With this conservative estimating practice, there is little to be gained with respect to the high cost of collecting water samples."

TIPRO commented that, "The commission should consider the practical enforceability of gas and liquid sampling requirements. A preconstruction requirement and a requirement to have site specific samples are not congruent. The facility will not be built until the well comes in and the product is known. Knowing the product is necessary before constructing the facility in compliance with regulations."

SWEPI commented "Where emissions are permitted from drip or slop tanks, emissions estimated from using Tanks 4.09 and E&P Tanks with process knowledge of the tank contents or guidance from API 19.1 standard are more representative than any given sample. This is because sampling is affected by seasonal and diurnal variations as well as the errors associated with grab sampling without consideration of working losses."

The commission is allowing the use of representative sampling for estimation of emissions. The representative sample must meet the defined criteria. Allowing the use of representative sampling should greatly reduce overall sampling costs for OGS in comparison to the proposed rule. The Regional office may at any time request a site-specific gas and liquid analysis, as is part of their requirements. The preconstruction registration requirement has changed to a preconstruction notification, with verification to follow as early as 90 days. The commission agrees

that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this comment and other comments including comments about the stringency of PBRs should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training. The commission agrees that process simulator outputs or calculations outputs can be used for upstream and downstream emissions calculations for other facilities in lieu of testing but only if the simulator outputs or calculations outputs are based on acceptable and appropriate inputs based on testing. The commission does not believe that emissions from produced water tanks are minimal. The commission agrees that very worst-case assumptions, such as assuming produced water is 100 percent crude oil, can be used for emissions calculations, if determined to be appropriate by the commission. Based on the commission's extensive experience with air pollution issues, the commission believes that actual site-specific sampling and testing yields the best representations of the actual operations of sites. Therefore, the commission does not change the rules to allow for guidance from industry reference sources to be used as a basis of emissions calculations in lieu of testing (unless already allowed in the rules). The commission notes that Produced water, even water associated with a "dry" well can have entrained VOCs. This is especially true of aromatics (including BTEX), which is why it is important to

quantify any BTEX that may be entrained in the produced water. This will allow for accurate quantification of these species for demonstrating impacts to off-property receptors. A representative analysis can be used if it meets the defined criteria.

SWEPI commented that, "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 eight hours of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance.

The representative sample must meet the defined criteria. Allowing the use of representative sampling should greatly reduce overall sampling costs for OGS in comparison to the proposed rule. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring.

SWEPI commented on Sampling General "required sampling includes three one hour test runs. While this is a well established protocol for continuous emissions monitoring from engines, heaters, and boilers, the accuracy, precision, and associated quality assurance is not well established for processes that may have intermittent emissions or variable cycle times. If this condition is combined with the condition where an already low VOC value is used for the vent before the control device, then there can be opportunity for great variability in removal efficiencies that may not be representative of overall continuous performance, Temperature cycling may also cause some pressure swings in and around the glycol condenser. This may contribute to non-representative samples. For these reasons sampling process points on glycol systems does not offer any advantages over use of models such as GRI's GlyCalc. We believe emissions sampling of the glycol reboiler vent stack, when not in a closed loop configuration, offers adequate emissions assurance along with demonstration of best management practices (BMP)."

The use of continuous emissions monitoring is an option for periodic evaluation of engines, not a requirement. The commission agrees that the validity of three one hour test runs for testing of sources, including engines and other sources typically operating steady-state, has been well established and that the applicable parameters for periodic evaluation of engines is dependent on engines testing results.

Encana commented, leak free is defined as detecting less than 10,000 ppmv of methane with either a portable analyzer suitable for method 21 or with an infrared camera designed to detect hydrocarbons. The language "Leak free is defined as detecting less than 10,000 ppmv of methane with either a portable analyzer suitable for method 21 or with an IR Camera designed to detect hydrocarbons," is being proposed for addition to the rule.

Devon commented on Table 7 Sampling and Demonstrations of Compliance LDAR - Testing of new and reworked piping connections. "The proposed rule requires gas or hydraulic testing be performed at no less than operating pressure using an approved gas analyzer within eight hours of the components being returned to service after repair. The use of an approved gas analyzer within eight hours is not practical, as this is costly specialized equipment that is usually rented from or provided through an LDAR testing company. It is sufficient to allow for leak checking to occur using audio, visual, and olfactory methods and other methods, such as using soap (or "snoop") to determine the presence of leaks. This can be performed after returning the repaired components to service and subsequent leaks can be fixed in an expeditious manner."

Encana commented that, "Due to the sheer volume of small sections of piping and fugitive equipment that are new or replaced, tracking each will be significant. Due the remoteness of many E&P locations, the cost and feasibility of regular leak detection will be very high and may not provide great environmental benefit. In our experience with voluntary leak detection programs at E&P facilities, we found that new facilities and new construction do not leak after routine checks are made using hydrotesting, bubble testing or even simple visual, auditory, or olfactory measures. The majority of leaks are found at older locations when an annual rotation is effective in leak detection and repair, Operators can often have multiple construction projects occurring simultaneously at different location. While Encana believes optical gas Imagining (sic imaging). Instrumentation is superior, it is unrealistic to require an $80,000 camera be located at each location. A trained operator could ensure that each location is monitored every eight hours with one camera. Encana recommends that this provision be removed or modified to require leak detection within a 14-day period which is consistent with EPAs Alternative Work Practice."

The commission changes the rule has adjusted the requirements to allow soap bubble testing within eight hours to look for leaks in lieu of instrument monitoring and to increase the time frame for instrument monitoring to 15 days. Additionally, gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service is an option in lieu of soap bubble testing and instrument testing. Instrument monitoring at sites is now only required where necessary to meet emission limitations. The use of a camera is an option, not a requirement.

Exterran recommended the rule be changed in "Engines, Periodic Evaluations (A) Requires quarterly performance tests for NO_X, CO and oxygen content.

The proposed rule has been changed in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 were re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. The commission believes that, given the changes to the rules, testing companies will not be overloaded.

Exterran commented that, "CTM-034 is not a standard method in the oil and gas industry. The rules should allow for equivalent, operator-defined methods which provide for a minimum calibration, three sampling runs, and post calibration drift checks. Recommendation: Allow alternate operator-defined methods provide for a minimum calibration, three sampling runs, and post calibration drift checks. Alternatively, allow a NELAC Accredited Method in lieu of the CTM-034 method."

After consideration, the commission changed language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufacturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing was added as an option in response to other comments.

Exterran commented that the rule "Currently requires another evaluation of engine performance after maintenance. Recommendation: Clarify or delete the general terms "engine maintenance" and "major component replacement, overhaul" and tie testing requirement to actions that could reasonably be expected to increase emissions."

The commission changes the proposed rule in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are were re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing

once every 4 years as long as half of each group is tested every 2 years. This represents savings of thousands of dollars a year for each engine that can take advantage of it. The commission deletes the requirement for formaldehyde testing from the proposed rule and determines that CO testing is an acceptable surrogate for formaldehyde testing for engines. The testing run duration is changed to match the period of the EPA test method.

SWEPI commented that, "Reports necessary to verify composition (including hydrogen sulfide (H_2S)) at any. 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 RVP;(ii) sales oil throughput; or (iii) condensate throughput. 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 at emission points. A representative sample can be used if the sample represents production from the same formation, field and depth. The sample should be representative of the sites to best estimate emission inventories."

The commission is allowing the use of representative sampling for estimation of emissions. The representative sample must meet the defined criteria. Allowing the use of representative sampling should greatly reduce overall sampling costs for OGS in comparison to the proposed rule. The Regional office may at any time request a site-specific gas and liquid analysis, as is part of their requirements.

The commission treats emissions inventories as distinct and different from authorizations or claims under PBRs, standards permits, and NSR permits. However, the commission notes and is aware of concerns OGS has with how emissions inventories and NSR interact and overlap. However, permitting must be done on a worst-case scenario, and emissions inventory are on an actual emissions scenario. Therefore, the commission assures that emissions inventory and NSR have worked together in the development of the gas or liquids."

TIPRO commented that there are issues in the proposed requirement for site-specific samples that will cause immediate non-compliance across the State as there is a lack of industry personnel, contractors, equipment and laboratories to handling the massive increase in sampling. Representative samples are sufficient for PBR registrations and insignificant emission sources.

Encana commented that, "Field wide averages are adequate for estimating emissions. Encana agrees with the TCEQ statement that the surrogate sample should be the most conservative of the represented sites to demonstrate worst-case scenario."

Devon commented on Table 7 Sampling and Demonstrations of Compliance LDAR Verify Composition of Materials. With this conservative estimating practice, there is little to be gained future with respect to the high cost of collecting water samples."

TIPRO commented that, "The commission should consider the practical enforceability of gas and liquid sampling unnecessarily redundant or overlapping requirements for OGS, those issues will be addressed at that time.

SWEPI commented that, "When hydrogen sulfide is either not present or present at low levels, a cost effective approach to measure H_2S is by colorimetric tubes (Draeger, Gastec, etc)."

The commission respectfully declines to change rule language in response to this comment. The use of stain tubes, including but not limited to, Draeger and Gastec tubes for determining sulfur content have always been allowed by this proposal.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "The requirement to monitor combustion devices is overly burdensome and seems to imply CEMS is required at remote and mainly unmanned OGS."

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Continuous temperature and oxygen monitoring on thermal oxidizers is overly burdensome and seems to imply CEMS is required at remote and mainly unmanned OGS. Data compiled by 6-minutes averages is unwarranted and not necessary to determine if the unit is operating properly. Daily averages are sufficient to that end. Allowances for more economical temperature recordings, such a strip charts, should be allowed. Most remote sites do not have electric power to run data loggers. Specifically, they recommended rule language "The temperature and oxygen measurement devices shall reduce the temperature and oxygen concentration readings to an averaging period of 6 minutes or less daily and record it at that frequency. Measurement devices may include strip charts for recording temperature.""

The commission recognizes regulation 30 TAC Chapter 25 for NELAC certification specifies the conditions when test or sampling results must be certified prior to submission to the TCEQ. As a result, the Table 8 condition describing requirements for Chapter 25 has been deleted as being redundant with those regulations.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Define enhanced monitoring to be applicable to the greatest efficiency claims and add language that indicates runtime will be tracked to indicate continuous disposition of the waste gas stream. 6-minute averages represents a tremendous amount of data that is overkill for demonstrating an enhanced monitoring claim. The requirement should be changed to annual averages, which is consistent with NESHAP, Subpart HH. 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. Basic monitoring is any continuous monitor that indicates when the flame in the device is on or off.

In response to comments, the commission changes the rule to indicate that control is not mandatory at a PBR site unless it is necessary to meet emission limitations. The company may apply monitoring associated with the level of control necessary to comply with emissions limitations, and the level of control may require continuous emissions monitoring systems (CEMS) monitoring as specified in the PBR OGS rule even if the location is remote and unmanned. Additionally, based on the commission's previous experience with review of OGS registrations and with Region's experience with OGS, the commission determines that more extensive parametric monitoring is needed for the highest effectiveness of control, as the highest effectiveness of control and the extensive use of such control are typically claimed to keep relatively large OGS operations under PBR emission limits; therefore, the commission determines that the more extensive parametric monitoring is needed for practical enforceability. The commission believes the continuous temperature and oxygen monitoring as applicable for the level of control claimed is appropriate. Where control with higher efficiency is necessary to meet emission limits, failure of the control for even a short period of time can cause substantive emissions. 6-minute reading averages is the longest period deemed acceptable. There is no preclusion for using a strip chart so long as the instrument response and records show the temperature and other parameters, if required, at intervals equal to or less than every 6 minutes. The commission notes that the regulatory need for updating §106.352 and for what the commission must

consider for nonattainment areas of the state is different than what the EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost and recordkeeping to industry. However, in this case, the commission believes the more extensive parametric monitoring is appropriate if a company needs to claim the highest effectiveness of control, even if under PBR. Additionally, the commission does not necessarily consider a glycol unit reboiler firebox subject to 40 CFR 63 MACT HH to also be a thermal oxidizer. Based on responses to all comments and based on based on the resulting changes to the PBR rule, the commission believes that monitoring recordkeeping requirements are sufficiently defined and specified. The commission added language to the new OGS rules providing the option for claiming 8,760 hr/yr run-time at maximum design capacity for any combustion unit instead of process monitoring. Testing for process heaters can be requested at Region's discretion. The commission does not anticipate requesting testing of heaters that are used as voluntary control devices or are not used as control devices. The commission clarifies language to indicate applicability to all combustion devices including engines and turbines, and deleted redundant rows from the table. In response to this comment and other comments including comments about the stringency of PBRs should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. The commission agrees that monitoring of the specific parameters listed in this

comment can be effective parameters to monitor for demonstration of compliance.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "Weekly sampling of cooling water at manned sites for dissolved solids is excessive. Suggest reducing frequency to monthly to be consistent with the monthly VOC monitoring in the cooling tower water in Table 8. Specifically " 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 monthly at manned and unmanned sites and maintain records of the monitoring results and all corrective actions."

The commission agrees that a monthly TDS check should be adequate for sites that can operate under the PBR. The commission does not expect that there will be unmanned sites operating cooling tower heat exchange systems. Companies must operate these systems carefully with sufficient blowdown to avoid solids buildup and loss of heat exchange capacity due to plugging.

Encana commented on Table 8 PBR §106.352 and Standard Permit- Category -- Boilers, Reboilers, Heater-Treaters, and Process Heaters.

The commission determines that the changes to testing requirements are sufficient, and therefore the commission did not change the rule to allow for the

future frequency for future testing to be based on past testing results.

The proposed rule has been changed in response to comments. The requirement for formaldehyde testing has been removed from the proposed rule. The testing run duration has been changed to match the period of the EPA test method. TCEQ has removed the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The commission changed the frequency for monitoring from quarterly to semiannually. After consideration, the commission changes language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufacturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing is added as an option. The regulatory need for updating §106.352 is different than what the EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules or TCEQ must consider for nonattainment areas of the state. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used for state purposes and minimize any additional cost to industry. Also, not all engines regulated by the proposed rule are addressed by the regulations mentioned in the comments. The commission does did not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512.

The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost and recordkeeping to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments. The commission agrees that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this comment, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training.

One individual stated a specific concern "is the H_2S content in the Eagle Ford Shale gas and the fact that it trends too much higher concentrations are the wells produce over time."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.

Based on comments received, language was added to indicate out of state testing reports claimed for initial testing of engines and turbines do not need to be

submitted unless requested by the commission.

After re-evaluation, the commission deleted the testing requirements for testing after maintenance. The commission determined that normally scheduled semi-annual or biennial testing will be sufficient for addressing testing after maintenance.

Devon commented on Table 7 Sampling and Demonstrations Engines - Periodic evaluation. Devon commented, "This section requires portable analyzer testing every calendar quarter, which goes beyond federal NSPS and NESHAP requirements and is not required in §106.512, which remains as an applicable PBR for engines in other industries. Furthermore, the quarterly testing requirements here are consistent with the Chapter 117 nonattainment rules, in 30 TAC §117.8140(b), and are not justified or warranted to be applied to engines statewide. Quarterly testing is costly and economically unwarranted for smaller engines (less than 500 hp). Devon recommends using the framework established in §106.512 to consistently regulate industries in Texas. In the event quarterly testing remains as a requirement, Devon suggests extending the test frequency in a phased approach based on the results of previous tests. For example, after four consecutive quarters of testing that indicates the engine is in compliance, extend the frequency to annual testing. Finally, there are not enough testing companies in Texas to conduct portable analyzer testing on a quarterly basis statewide. Portable analyzer testing is time consuming, onerous, and would result in significant cost increases on operators due to testing costs and additional manpower needs. Alternative test methods, such as stain tube or other operator defined methods should be allowed for quarterly emission evaluations."

After re-evaluation, the commission deletes the testing requirements for testing after maintenance of engines. The commission determines that normally scheduled semi-annual or biennial testing of engines will be sufficient for demonstration of compliance for engines.

"This section requires portable analyzer testing every calendar quarter, which goes beyond federal NSPS and NESHAP requirements and is not required in §106.512, which remains as an applicable PBR for engines in other industries. Furthermore, the quarterly testing requirements here are consistent with the Chapter 117 nonattainment rules, in 30 TAC §117.8140(b), and are not justified or warranted to be applied to engines statewide. Quarterly testing is costly and economically unwarranted for smaller engines (less than 500 hp). Finally, there are not enough testing companies in Texas to conduct portable analyzer testing on a quarterly basis statewide. Portable analyzer testing is time consuming, onerous, and would result in significant cost increases on operators due to testing costs and additional manpower needs.

The commission changes the rule in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. This represents savings of thousands

of dollars a year for each engine that can take advantage of it. The commission deletes the requirement for formaldehyde testing and determines that CO testing is an acceptable surrogate for formaldehyde testing for engines. The testing run duration is changed to match the period of the EPA test method. The commission removes the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The commission does not change the frequency for monitoring from quarterly to semiannually. Quarterly testing is no more stringent than what is required at Title V sites. After consideration, the commission changes language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufaturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing is added as an option. The commission does not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments. The commission determines that the changes to testing requirements are sufficient,

and therefore the commission did not change the rule to allow for the future frequency for future testing to be based on past testing results. The commission agrees that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this comment and other comments including comments about the stringency of PBRs should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training. The commission does not understand the portion of the comment about the framework established in PBR §106.512.

The commission deleted testing requirements for engines <500 hp from the new PBR rule.

"(C) 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 2 weeks, Encana Response: This requirement appears to be adopted from 30 TAC §117.8140(b) which is applicable to NO_X sources located in nonattainment and early action counties. Extending its applicability to sources located in attainment areas and unmanned rural areas would be extremely burdensome and not provide additional environmental benefit. However, Encana believes that the requirement to conduct performance tests after maintenance should remain applicable to those engines subject to 30 TAC Chapter 117."

The proposed rule has been changed in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years.The requirement for formaldehyde testing has been removed from the proposed rule. The testing run duration has been changed to match the period of the EPA test method. The commission believes that, given the changes to the rules, testing companies will not be overloaded. The commission did not add language specifically for engines in 30 TAC Chapter 117 counties. Rule language for 30 TAC Chapter 117 counties would need to be addressed in rulemaking for 30 TAC Chapter 117.

Representative gas and liquid analysis will be accepted for registration purposes if they meet the criteria defined in the preamble.

Encana stated that the commission should "consider the practical enforceability of gas and liquid sampling requirements.

The commission is allowing the use of representative sampling for estimation of emissions. The representative sample must meet the defined criteria. Allowing the use of representative sampling should greatly reduce overall sampling costs for OGS in comparison to the proposed rule. The Regional office may at any time request a site-specific gas and liquid analysis, as is part of their requirements.

Encana encourages solutions such as emission factor development or representative sampling."TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that the "TCEQ should allow for the use of representative gas and liquid analysis as opposed to site specific analysis so long as certain criteria are met for characterizing the analysis as representative. The following items could be used for defining whether an analysis is representative or not: Production type: grouping of fields or wells within fields on the basis of gas or oil production. Same or similar producing reservoirs: grouping of fields on the basis of reservoir types such as tight sands, coal bed methane, conventional sands, and shale gas. Different named formations/reservoirs with the same classification, such as tight sands, with less than 2,000 vertical feet between the formation tops could be grouped. Similar ranges of pressure and temperature for the initial phase separation of production from the wells. Although the pressure can vary quite widely, for even the same producing horizon/formation, dependent on "well-head" compression the general collection and gathering system pressure in the fields being grouped should be similar. Similar fluid compositions such as oil with associated hydrocarbon gas, primary hydrocarbon gas production with hydrocarbon liquids that separate at field separators, "dry" gas with no appreciable (<2 barrels per MMSCF) hydrocarbon liquid production. Similar API gravity could be used for demonstration purposes. Similar production arrangements, surface equipment, and operational characteristics/practices: Fields to be grouped should employ similar production approaches such as well-site phase separation with equipment located on or near individual well sites or small groups of wells, multi-phase flow to central separation and production facilities (such as central tank batteries). Also they could be grouped by similar treatment of the gas or liquids."

TIPRO commented that the "proposed requirement for site-specific samples will cause immediate non-compliance across the State as there is a lack of industry personnel, contractors, equipment and laboratories to handling the massive increase in sampling. Representative samples are sufficient for PBR registrations and insignificant emission sources."

Encana commented that, "Field wide averages are adequate for estimating emissions. Permit reviewers can determine whether site specific samples are necessary based on a minimum data set of 3 samples per field. Another approach that has been allowed by the Agency for the past year is the use of analog samples that represent production form (sic from) the same formation, field and depth. Encana agrees with the TCEQ statement that the surrogate sample should be the most conservative of the represented sites to demonstrate worst-case scenario."

Devon commented on Table 7 Sampling and Demonstrations of Compliance, LDAR Verify Composition of Materials, all site specific gas or liquid analyses. "This section includes language that requires extended GC analyses be obtained for certain gas and liquid streams, and subsequently used for compliance demonstrations. This includes: (D) Tanks for liquids and vapors; and (E) Produced water or brine/salt water at the inlet prior to storage. TCEQ-approved methods for calculating emissions from tanks do not require site specific sampling be obtained for storage tank liquid and vapor, as well as produced water. For the emissions calculations, a pressurized sample at the separator is needed along with the API gravity and RVP of the sales oil. With this conservative estimating practice, there is little to be gained with respect to the high cost of collecting water samples."

TIPRO commented that, "The commission should consider the practical enforceability of gas and liquid sampling requirements. A preconstruction requirement and a requirement to have site specific samples are not congruent.

The preconstruction registration requirement has changed to preconstruction notifications, with verification to follow as early as 90 days.

The commission is allowing the use of representative sampling for estimation of emissions. The representative sample must meet the defined criteria. Allowing the use of representative sampling should greatly reduce overall sampling costs for OGS in comparison to the proposed rule. The Regional office may at any time request a site-specific gas and liquid analysis, as is part of their requirements. The preconstruction registration requirement has changed to preconstruction notifications, with verification to follow as early as 90 days. The commission agrees that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this comment and other comments including comments about the stringency of PBRs

should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training.

An individual commented that H_2S content is very low when a well first begins production, and concentrations escalate over time but become permitted at very low levels. This is wrong and needs to be corrected.

A site and stream specific H_2S analysis will have to be performed. The regional office may at any time request additional or new test to verify this composition and emission estimates.

SWEPI commented that, "When hydrogen sulfide is either not present or present at low levels, a cost effective approach to measure H_2S is by colorimetric tubes (Draeger, Gastec, etc).

The commission agrees that some oil and gas wells in some oil and gas fields can change from sweet to sour or becomes more sour over time. The PBR rule requires sampling and testing including sampling and testing for hydrogen sulfide. Also, Region can request sampling and testing if deemed necessary (e.g., Region

may request sampling and testing due to nuisance issues or compliance issues). Additionally, the Texas Railroad Commission can require quarterly reporting for hydrogen sulfide. Based on the changes to the rule in response to all comments, the commission believes that the OGS PBR rule clearly indicates that registrations must be submitted or revised if current representations or certifications change to the extent that rule language requires such submittals.

SWEPI commented "For VOC emissions, there are three potential alternative VOC emissions testing methods that are well suited for VOC emissions C10+ speciation and less costly than the proposed method. The first of these is with a hand held PID instrument such as NMNEVOC calibrated on propane. Secondly, a continuous Flame Ionization Instrument (FID) can be used if it is corrected to adjust for methane and ethane by either a gas composition analysis with speciation or via an IR VOC cell. Using the IR VOC cell is the best suited method for VOC emissions C10-+- speciation. The third method is to use an IR cell with and without an activated carbon trap. All these methods are methods are less costly and less labor-intensive than the proposed extended ASTM 1946 or CTM-035 with flame ionization detector."

Hand-held instruments PIDs tend to have a smaller dynamic range as compared to FIDs and would not be the detector of choice for measuring high concentrations. PIDs also tend to have water vapor problems, and as proposed, would not be calibrated with the actual gases of interest. Additionally, IR VOC Cells tend to have interference from water and CO_2, along with water vapor condensation issues. Dusty areas and particulate matter can also negatively affect the performance.

The extended ASTM 1946 or CTM-035 methods have been proven effective and are desirable because measurements are based on calibrations for specific compounds using appropriate gas standards, as opposed to making corrected adjustments. Therefore, the commission did not change the rule in response to this comment. As a result, the Table 8 condition describing requirements for 30 TAC Ch 25 has been deleted as being redundant with those regulations.

One individual commented that, "When monitoring is required, all QA/ QC shall follow 30 TAC Ch 25 NELAC accreditation requirements. Recommendation: Clarify or delete the general terms "engine maintenance" and "major component replacement, overhaul" and tie testing requirement to actions that could reasonably be expected to increase emissions. Also, request clarification that such testing could satisfy quarterly testing requirement as well."

After re-evaluation, the commission deletes the testing requirements for testing after maintenance of engines. The commission determines that normally scheduled semi-annual or biennial testing of engines will be sufficient for demonstration of compliance for engines.

Furthermore, the quarterly testing requirements here are consistent with the Chapter 117 nonattainment rules, in 30 TAC §117.8140(b Extending its applicability to sources located in attainment areas and unmanned rural areas would be extremely burdensome and not provide additional environmental benefit. However, Encana believes that the requirement to conduct performance tests after maintenance should remain applicable to those engines subject to 30

TAC Chapter 117."

The commission changes the rule in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. This represents savings of thousands of dollars a year for each engine that can take advantage of it. The commission deletes the requirement for formaldehyde testing and determines that CO testing is an acceptable surrogate for formaldehyde testing for engines. The testing run duration is changed to match the period of the EPA test method. The commission removes the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The commission does not change the frequency for monitoring from quarterly to semiannually. Quarterly testing is no more stringent than what is required at Title V sites. After consideration, the commission changes language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufaturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing is added as an option. The commission does not delete the requirement for

biennial testing. Biennial testing is already a requirement in PBR §106.512. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments. The commission determines that the changes to testing requirements are sufficient, and therefore the commission did not change the rule to allow for the future frequency for future testing to be based on past testing results. The commission agrees that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this comment and other comments including comments about the stringency of PBRs should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training. The commission does not understand the portion of the comment about the framework established in PBR §106.512. The commission did not add language specifically for engines in 30 TAC Chapter 117 counties. Rule language for 30 TAC Chapter 117 counties would need to be addressed in rulemaking for 30 TAC Chapter 117.

It is unlikely that available lab resources exist now or in the near term years to accommodate the volume of sample analysis anticipated by rule requirement. They recommended that the commission allow the use of representative reporting field level data; Require "site-specific" data only in critical emission sources; Require "site-specific" data only where estimated emissions are close to thresholds."

The commission is allowing the use of representative sampling for estimation of emissions. The representative sample must meet the defined criteria. Allowing the use of representative sampling should greatly reduce overall sampling costs for OGS in comparison to the proposed rule. The Regional office may at any time request a site-specific gas and liquid analysis, as is part of their requirements. The preconstruction registration requirement has changed to a preconstruction notifications, with verification to follow as early as 90 days. The commission agrees that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this comment and other comments including comments about the stringency of PBRs should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training. The commission agrees that process simulator outputs or calculations outputs can be used for upstream and

downstream emissions calculations for other facilities in lieu of testing but only if the simulator outputs or calculations outputs are based on acceptable and appropriate inputs based on testing. The commission does not believe that emissions from produced water tanks are minimal. The commission agrees that very worst-case assumptions, such as assuming produced water is 100 percent crude oil, can be used for emissions calculations, if determined to be appropriate by the commission. Based on the commission's extensive experience with air pollution issues, the commission believes that actual site-specific sampling and testing yields the best representations of the actual operations of sites. Therefore, the commission does not change the rules to allow for guidance from industry reference sources to be used as a basis of emissions calculations in lieu of testing (unless already allowed in the rules).

The first of these is with a hand held PID instrument such as NMNEVOC calibrated on propane. Secondly, a continuous Flame Ionization Instrument (FID) can be used if it is corrected to adjust for methane and ethane by either a gas composition analysis with speciation or via an IR VOC cell. Using the IR VOC cell is the best suited method for VOC emissions C10-+- speciation. The third method is to use an IR cell with and without an activated carbon trap. All these methods are methods are less costly and less labor-intensive than the proposed extended ASTM 1946 or CTM-035 with flame ionization detector."

Hand-held instruments PIDs tend to have a smaller dynamic range as compared to FIDs and would not be the detector of choice for measuring high concentrations.

PIDs also tend to have water vapor problems, and as proposed, would not be calibrated with the actual gases of interest. Additionally, IR VOC Cells tend to have interference from water and CO_2, along with water vapor condensation issues. Dusty areas and particulate matter can also negatively affect the performance. The extended ASTM 1946 or CTM-035 methods have been proven effective and are desirable because measurements are based on calibrations for specific compounds using appropriate gas standards, as opposed to making corrected adjustments. Therefore, the commission did not change the rule in response to this comment.

One individual commented that, "When monitoring is required, all QA/ QC shall follow 30 TAC Ch 25 NELAC accreditation requirements. i) In cases where the most appropriate case for monitoring is not a method offered for certification by the TCEQ, what documentation or steps should be taken?"

SWEPI wanted to "confirm that when monitoring is required, all QA/QC shall follow 30 TAC Ch 25 NELAC accreditation requirements for collected laboratory samples."

The commission has removed the reference; however NELAC accreditation requirements still apply. Additionally, NELAC language has been added specifically for engines in response to other comments. The commission is constantly adding new labs and test methods, so in the future, NELAC accredited testing may be required. Documentation of testing and methods should make a common sense connection to the requirement demonstrated with accuracy and

precision commensurate with the potential proximity of the emission estimate to the allowable standard.

Devon commented on Table 8: Monitoring and Records Demonstrations Equipment Specifications – "Process units, tanks, vapor recovery units, flares, thermal oxidizers, and reboiler control devices: This section requires records be kept for volumes, pressures, design specifications, equipment sizing, etc. Devon recommends that the section is more specifically phrased toward keeping records directly related to air emissions, with recommended language as follows: "Emissions control equipment specifications, volumes and pressures of process streams, and pertinent compositions used for emissions calculations shall be available at the nearest manned facility or at the owner/operator company headquarters.""

The commission concurs with this comment and changes the language to the following: a copy of the registration and emission calculations including the fixed equipment sizes or capacities and manufacturer's specifications and programs to maintain performance, with the plan and records for routine inspection, cleaning, repair and replacement. The following is language from the final rule: 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.

The TCEQ is revising the requirements with respect to instrument fugitive monitoring requirements for the PBR and placing the requirements in table 10 to be applicable only when desired by a company to certify lower emission potential

or when necessary and elected for meeting emission limitations. The new BMP language maintains a physical inspection quarterly with the simple check box kind of record with notes of leakers as suggested. When a company chooses the more extensive LDAR program for emission reductions, the weekly check on components is required. The commission believes operators can be, generally are attentive and responsive to leaks as noted, but feel a conscious note with the concept of being responsible and aware of the environmental protection responsibility, requires a simple record note of the task.

In response to this comment and other comments, the commission changes language in the OGS PBR rule to indicate all fugitive components need to be physically inspected for leaks on a quarterly basis. The commission determines in response to comments that the initially proposed monitoring requirements for fugitive components were too stringent (That is PBR requirements do not necessarily match BACT requirements.) for fugitive components under the OGS PBR. Therefore, the commission re-evaluates what is required for fugitive monitoring under the OGS PBR. The commission intentionally avoids the use of AVO as AVO is actually LDAR. Physically inspecting for leaks is not LDAR. Additionally, the commission believes it is reasonable to assume that OGS will not want to lose substantial amounts of product. As such, the commission determines that all fugitive components need to be physically inspected quarterly for leaks. The recordkeeping requirements for physical inspections for leaks are not detailed records are not nearly as stringent as recordkeeping requirements for LDAR. The PBR rule also allows for the use of voluntary LDAR or required federal LDAR

(such as LDAR for 40 CFR 60 NSPS KKK or GHG Supart W); weekly physical inspections are required in tandem with LDAR. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments.

532 TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko recommended to, "Remove "continuous" monitoring, as this implies temperature transmitter. Allow for weekly temperatures recorded from local thermometer, thermal gun, or other. Continuous temperature monitoring is a significant cost burden on small remote OGS. Thermowells, temperature transmitters, power supply, and remote monitoring historian SCADA system would be required. Unwarranted for claims 90 percent and less, basic monitoring should be periodic monitoring of weekly temperature readings of waste gas outlet from condenser. Daily temperature readings are not possible for remote, unmanned OGS; however, the sites are visited at least weekly. Flow conditions redundant with data already collected."

The commission changes the rule to require a spot check of the temperature with the weekly time frame as suggested in this comment. For the PBR where a condenser is necessary to meet emission limitations and the claimed control efficiency, the owner/operator must follow the sampling, monitoring and

recordkeeping.

VOC testing has been eliminated as an automatic requirement for testing and monitoring.

The commission changes the rule in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. This represents savings of thousands of dollars a year for each engine that can take advantage of it. The commission deletes the requirement for formaldehyde testing and determines that CO testing is an acceptable surrogate for formaldehyde testing for engines. The testing run duration is changed to match the period of the EPA test method. The commission removes the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The commission does not change the frequency for monitoring from quarterly to semiannually. Quarterly testing is no more stringent than what is required at Title V sites. After consideration, the commission changes language in

the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufaturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing is added as an option. The commission does not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments.

The proposed rule has been changed in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 were to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. The commission changes the rule in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are re-evaluated to allow for previous tests to suffice for

initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. This represents savings of thousands of dollars a year for each engine that can take advantage of it. The requirement for formaldehyde testing has been removed from the proposed rule. The commission deletes the requirement for formaldehyde testing and determines that CO testing is an acceptable surrogate for formaldehyde testing for engines. The testing run duration is changed to match the period of the EPA test method. The commission removes the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The commission does not change the frequency for monitoring from quarterly to semiannually. Quarterly testing is no more stringent than what is required at Title V sites. After consideration, the commission changes language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufaturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing is added as an option. The commission does not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply

with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko stated that "there needs to be a standardized compliance determination. The standard should reference a maximum achievable site load."

Subsection (m), Table 6 requires required a minimum load of 50 percent for initial and biennieal testing. The proposal has been altered to address situations were an engine is idle, but the requirement to operate at 50 percent or greater load is was not changed in response to this comment. The commission TCEQ believes that a 50 percent load this load is achievable for all engines subject to testing and does not impose any burden on permit holders. Periodic evaluation monitoring does did not require any specific load and was not changed.

Devon commented on Table 8: Monitoring and Records Demonstrations Boilers, Reboilers, Heater-Treaters, and Process Heaters: "The proposed rule requires records of hours of operation of every combustion device of any size by use of a process monitor such as a "runtime meter". Devon proposes that maximum burner duty and maximum annual operating time of 8,760 hours be allowed for emissions calculations in lieu of tracking runtime at every individual combustion device."

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko "Propose default efficiency of 50 percent for cyclic service heaters/reboilers without requiring additional monitoring per Table 7 - Records of operational monitoring and testing records. For process heaters, boilers, reboilers, and heater treaters that do NOT serve as emission control devices or where waste gas is utilized in the fuel system, the maximum annual runtime of 8,760-hours may be used to calculate emissions in lieu of runtime tracking. For process heaters, boilers, reboilers, and heater treaters that DO serve as emission control devices, a default destruction efficiency factor of up to 50 percent may be claimed with no additional runtime monitoring or testing. For control efficiency claims greater than 50 percent, records of the hours of operation must be demonstrated by using heater parametric monitoring indicators, including but not limited to, fuel gas usage, flame or fire-eye monitors, process temperature, heater stack temperature, heater firebox pressure, valve position documented by a log book entry, or other valid means of demonstrating heater runtime.

The commission is not aware of engines and turbines being used as control devices at OGS. The commission clarified language to indicate applicability to all combustion devices including engines and turbines, and deleted redundant rows from the table. Based on comments received, language was added to indicate out of state testing reports claimed for initial testing of engines and turbines do not need to be submitted unless requested by the commission.

The commission added language to the new OGS rules providing the option for claiming 8,760 hr/yr run-time at maximum design capacity for any combustion unit instead of process monitoring. The commission is not aware of engines and

turbines being used as control devices at OGS. Testing for process heaters can be requested at Region's discretion. The commission does not anticipate requesting testing of heaters that are used as non-voluntary control devices or are not used as control devices. The commission clarifies language indicate applicability to all combustion devices including engines and turbines, and deleted redundant rows from the table. The commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. The commission changes monitoring requirements for reboilers. Monitoring is now required for reboilers if a control efficiency of greater than 50 percent is claimed

Devon commented on Table 8: Monitoring and Records Demonstrations Fuel Records - VOC and Sulfur Content: "This section of the proposed rule reads, "For each separate fuel gas use at the site, the fuel usage and VOC content if the VOC content was used in the emission estimation." This requirement implies that fuel must be measured at each combustion device, which represents a significant undue burden resulting in minimal impact on emissions. Devon recommended rule changes to Records of Operational Monitoring and Testing Records: "Records of the hours of operation of every combustion device and engines of any size by the use of a process monitor such as a run time meter. The owner or operator may choose to undergo testing, as identified in Table 7, in lieu of installing a process monitor and recording the hours of operation.""

The commission adds language to clarify fuel usage measurement. The

commission added an option for not requiring fuel flow meters. The commission added language to clarify VOC content of fuel. The commission added language to the new OGS rules providing the option for claiming 8,760 hr/yr run-time at maximum design capacity for any combustion unit instead of process monitoring. Testing for process heaters can be requested at Region's discretion. The commission does not anticipate requesting testing of heaters that are used as voluntary control devices or are not used as control devices. The commission clarified language to indicate applicability to all combustion devices including engines and turbines, and deleted redundant rows from the table. Based on comments received, language was added to indicate out of state testing reports claimed for initial testing of engines and turbines does not need to be submitted unless requested by the commission.

The commission changes the rule in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. This represents savings of thousands of dollars a year for each engine that can take advantage of it. The commission deletes the requirement for formaldehyde testing and determines that CO testing is an acceptable surrogate for formaldehyde testing for engines. The testing run duration is changed to match the period of the EPA test method. The commission

removes the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The commission does not change the frequency for monitoring from quarterly to semiannually. Quarterly testing is no more stringent than what is required at Title V sites. After consideration, the commission changes language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufaturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing is added as an option. The commission does not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments. The commission determines that the changes to testing requirements are sufficient, and therefore the commission did not change the rule to allow for the future frequency for future testing to be based on past testing results. The commission agrees that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this

comment and other comments including comments about the stringency of PBRs should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training. The commission does not understand the portion of the comment about the framework established in PBR §106.512. The commission did not add language specifically for engines in 30 TAC Chapter 117 counties.

SWEPI commented that, "The periodic sampling for engines should consider CTM-034 testing should be allowed to be conducted by the operator. This can then be complemented by complete 3rd party stack testing once every 2 years if quarterly performance consistently meets permitted emissions requirements.

The proposed rule has been changed in response to this comment. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 allow for previous tests to suffice for initial testing when a new engine is brought on-site and to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years.The requirement for formaldehyde testing has

been removed from the proposed rule. The testing run duration has been changed to match the period of the EPA test method. Also, testing after maintenance has been removed from the proposal and the proposal has been changed to say portable analyzers do not have to meet CTM-034 and must only be operated according to manufacturer's instructions.

SWEPI commented that more specifically, the 30 TAC 116 states that "the new standard permit would require testing for emissions of total VOCs and formaldehyde from engines" whereas the 30 TAC §106.352 states that "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." Please note that standard methods and calibration standards for formaldehyde are not well developed or widely used at this time and consequently require highly specialized and costly equipment, such as Fourier Transform Infrared (FTIR) spectrometers."

VOC and formaldehyde testing has been removed from the proposal in response to this comment.

The commission changes the rule in response to comments. Periodic monitoring is now only required for sources subject to Title V Operating permits and it is a federally required condition for those permits. Additionally, the EPA reference method testing requirements of the current §106.512 are re-evaluated to allow for previous tests to suffice for initial testing when a new engine is brought on-site and

to allow for similar groups of engines to undergo testing once every 4 years as long as half of each group is tested every 2 years. This represents savings of thousands of dollars a year for each engine that can take advantage of it. The commission deletes the requirement for formaldehyde testing and determines that CO testing is an acceptable surrogate for formaldehyde testing for engines. The testing run duration is changed to match the period of the EPA test method. The commission removes the requirement for VOC testing from the proposal in response to this comment. The commission believes CO is an adequate surrogate for VOC and that the initial sampling for CO combined with quarterly monitoring for CO at larger emission sites holding a federal operating permit represents appropriate VOC monitoring. The commission does not change the frequency for monitoring from quarterly to semiannually. Quarterly testing is no more stringent than what is required at Title V sites. After consideration, the commission changes language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufaturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing is added as an option. The commission does not delete the requirement for biennial testing. Biennial testing is already a requirement in PBR §106.512. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are

addressed by the federal regulations mentioned in all the comments. The commission determines that the changes to testing requirements are sufficient, and therefore the commission did not change the rule to allow for the future frequency for future testing to be based on past testing results. The commission agrees that there are not enough testing companies to addressing some of the monitoring and testing requirements as initially proposed. In response to this comment and other comments including comments about the stringency of PBRs should not necessary be the same as BACT, the commission changes language in the PBR rule for some of the control devices to only require monitoring and testing when controls are needed to meet impacts evaluations or when certain control efficiencies are claimed. Also, the commission adds stain tube testing for periodic monitoring of engines and determines that stain tube testing can be performed by operators after a minimal amount of training. The commission does not understand the portion of the comment about the framework established in PBR §106.512. The commission did not add language specifically for engines in 30 TAC Chapter 117 counties. Rule language for 30 TAC Chapter 117 counties would need to be addressed in rulemaking for 30 TAC Chapter 117.

Encana commented, "Leak free is defined as detecting less than 10,000 ppmv of methane with either a portable analyzer suitable for method 21 or with an IR Camera designed to detect hydrocarbons." is being proposed for addition to the rule."

The rule for voluntary LDAR sites is being changed to only require monitoring

prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service at voluntary LDAR sites. Where technically feasible new and reworked components may be screened for leaks with a soap bubble test within eight hours of being returned to service in lieu of instrument testing. Gas or hydraulic testing with a time factor for monitoring by is being removed as a requirement from the PBR. Any testing and monitoring requirement will only be applicable to voluntary LDAR programs.

Instrument monitoring at sites is now only required where necessary to meet emission limitations. The TCEQ changes the rule to allow soap bubble testing within eight hours to look for leaks in lieu of instrument monitoring and to increase the time frame for instrument monitoring to 15 days. Additionally, gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service is an option in lieu of soap bubble testing and instrument testing. The use of a camera is an option, not a requirement.

SWEPI stated that, "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. 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), except as specified in subsection (e)(7) of this standard permit for Best Management Practices and will only be required to have a record retention of 2 years, as stated under the TCEQ Voluntary AWP LDAR Monitoring section."

The commission changes the analyzer provision in Table 7 exempting the annual Test Method 21 requirement in 40 CFR §60.18(h)(7) and the reporting requirement in 40 CFR §60.18 (i)(5). The requirement is being changed to reflect that LDAR is a voluntary control that a company may select to reduce the fugitive emissions. Record retention is 2 years for state purposes and 5 years for federal purposes. However, in accordance with §101.153 for AWP LDAR, the record retention period is 5 years.

The TCEQ concurs and has changed the BMP to only require a physical inspection. Instrument monitoring requirements are reserved for sites where monitoring

reduction credit is necessary to meet emission limitations. We do want to encourage sites to use the incentive program in 30 TAC Chapter 101.

In response to this comment and other comments, the commission changes language in the OGS PBR rule to indicate all fugitive components need to be physically inspected for leaks on a quarterly basis. The commission determines in response to comments that the initially proposed monitoring requirements for fugitive components were too stringent (That is PBR requirements do not necessarily match BACT requirements.) for fugitive components under the OGS PBR. Therefore, the commission re-evaluates what is required for fugitive monitoring under the OGS PBR. The commission intentionally avoids the use of AVO as AVO is actually LDAR. Physically inspecting for leaks is not LDAR. Additionally, the commission believes it is reasonable to assume that OGS will not want to lose substantial amounts of product. As such, the commission determines that all fugitive components need to be physically inspected quarterly for leaks. The recordkeeping requirements for physical inspections for leaks are not detailed records are not nearly as stringent as recordkeeping requirements for LDAR. The PBR rule also allows for the use of voluntary LDAR or required federal LDAR (such as LDAR for 40 CFR 60 NSPS KKK or GHG Supart W); weekly physical inspections are required in tandem with LDAR. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other

federal or states rule to also be used in order to minimize any additional cost to industry. Also, not all facilities regulated by the OGS PBR are addressed by the federal regulations mentioned in all the comments. Instrument monitoring at sites is now only required where necessary to meet emission limitations. The TCEQ changes the rule to allow soap bubble testing within eight hours to look for leaks in lieu of instrument monitoring and to increase the time frame for instrument monitoring to 15 days. Additionally, gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service is an option in lieu of soap bubble testing and instrument testing. The use of a camera is an option, not a requirement. Additionally, the commission encourages companies to participate in the incentive program under 30 TAC Chapter 101.

SWEPI wanted to "confirm that when monitoring is required, all QA/QC shall follow 30 TAC Ch 25 NELAC accreditation requirements for collected laboratory samples."

The regulation 30 TAC Chapter 25 for NELAC certification specifies the conditions when test or sampling results must be certified prior to submission to the TCEQ the rule as any reference is redundant with those requirements.

SWEPI commented on requirements for "Emissions stack testing must be performed using EPA methods 1 - 5 or by CTM -034.Sampling is required for VOC, benzene and H_2S at Region's discretion. The associated quality assurance and data validation must be performed and documented as per the method guidelines. 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 percent 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."

After consideration, the commission changed language in the rule from operate portable analyzers in accordance with EPA Test Method CTM-034 to operate in accordance with manufacturer's instructions, operator-defined test methods, or NELAC accredited test methods. Additionally, stain tube testing was added as an option in response to other comments.

Encana stated that in Table 7 for both the PBR and Standard Permit Sampling and Demonstrations of Compliance and Table 8 - Monitoring and Record Demonstrations (applicable to both the PBR and Standard Permit) "have several areas needing clarification that should be reviewed prior to finalization."

The commission has expanded the detail in the tables to help clarify the demonstration and records needed. Records that establish compliance with emission limitation have always been required. Process parameters that work in concert with the emission estimation can show the emissions are below the worst-case potential.

The commission changes and clarifies language in Table 7 and Table 8 in subsection (m) in response to this comment and other comments.

EDF support the sampling requirements. "However, we encourage the TCEQ to add a requirement to Table 7 for metering of storage tank emissions for wells above a certain production threshold (e.g., potential to emit > 5 tpy VOC) for a minimum representative period each quarter."

The commission does not change rule language in response to this comment. The commission believes where inlet material compositions are understood and documented the emission estimation procedures are adequate for these sources. The commission can request additional emission analysis and testing if when concerns arise.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "Engine Biennial testing prevents jumping forward to a new year without a short-cycle test. This context provides a way of extending the testing cycle via the 90-day buffer. "First initial" is redundant and inconclusive for enforcement purposes. They recommended rule changes: "Engines subject to testing shall be tested within 90 days of the 2 year anniversary date of their last compliance performance test."

The commission changes the rule in response to this comment to clarify the

language. The commenter has correctly stated the intent of the language.

The commission is allowing for the use of GRI-GlyCALC program for estimating condenser efficiencies. There will be minimum expectations for glycol dehydrators, and any additional controls and reductions are voluntary for meeting impacts.

The commission changes the rule to indicate that control monitoring is only necessary when control is needed to meet emission limitations or certify emissions with control. The more extensive parametric monitoring is only applicable where the highest effectiveness of the control is claimed. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules. The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. However, in this case, the commission believes the more extensive parametric monitoring is appropriate if a company needs to claim the highest effectiveness of control, even if under PBR and more stringent than a current federal rule. Additionally, the commission believes that the OGS rules clearly indicates that OGS must address worst-case emissions for impacts review, including worst-case emissions due to greatly reduced efficiencies during hot summer months for condensers cooled with ambient air. The commission

changes the rule to allow for claiming control efficiencies from outputs of GRI-GLYCalc emissions calculations.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko commented that, "Emergency engines should be exempt from testing requirements. If engines have not operated during the year, no testing should be required. Specifically "conduct evaluations of each engine performance every calendar quarter after initial compliance testing by measuring the NO_X, CO, and oxygen 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 3-month (quarterly) period. If an engine has been shutdown prior to a required test, it must be tested within 48 hrs of subsequent startup. Emergency use engines are exempt from this requirement."

The commission deletes the testing requirements for emergency engines in response to this comment. Testing is not required for emergency engines under case-by-case NSR permits. Therefore, testing cannot be justified under the OGS rules for emergency engines. However, language is added to the OGS background document to indicate that emissions from emergency engines do have to be included in impacts evaluations. The commission agrees that engines should not have to be started just for the purposes of testing the engine as required. Language has been added to the rule to specify when and what testing needs to be completed when an idle engine is re-started for normal production operation.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko commented that, "Stack testing for thermal oxidizers should apply to efficiency claims of 99 percent or greater, per the intent of §106.352(f)(6). "For thermal oxidizer efficiency claims of 99 percent or greater, stack testing must be coordinated and approved. Sampling is required for VOC, benzene and H_2S at Region's discretion. The thermal oxidizer (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.""

Stack testing for thermal oxidizers should apply to efficiency claims of 99 percent or greater, per the intent of §106.352 (f)(6).

The commission has clarified that control monitoring is only necessary when control is needed to meet emission limitations or certify emissions with control. The more extensive parametric monitoring is only applicable where the highest effectiveness of the control is claimed. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for nonattainment areas of the state is different than what the US EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost to industry. However, the commission believes the more extensive parametric monitoring is appropriate if a company needs to claim the highest effectiveness of control, even if under PBR and more stringent than a current federal rule.

SWEPI commented that, "The proposed PBR states that 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 depending on the pollutants and type of testing needed. However, analysis shows that these tests would most likely be $14,500 -- $24,500.00 based on condensers or VRU's and testing the components related to performance. These costs are very high and add little to no value for non emission points."

The commission has clarified that control monitoring is only necessary when control is needed to meet emission limitations or certify emissions with control. The more extensive parametric monitoring is only applicable where the highest effectiveness of the control is claimed. The test would only be required where the site could not meet emission limitations of the rule unless the best performance is achieved from the control. These are very critical control devices on the most significant emission sauces that are pushing the very limits of the use of PBRs.

The commission has clarified that control monitoring is only necessary when control is needed to meet emission limitations or certify emissions with control. The more extensive parametric monitoring is only applicable where the highest effectiveness of the control is claimed. The commission notes that the regulatory need for updating §106.352 and for what the commission must consider for

nonattainment areas of the state is different than what the EPA must consider when promulgating 40 CFR 60 NSPS or 40 CFR 61, 63 NESHAP rules The proposed PBR rule attempts to allow anything done to comply with other federal or states rule to also be used in order to minimize any additional cost and recordkeeping to industry. However, the commission believes the more extensive parametric monitoring is appropriate if a company needs to claim the highest effectiveness of control, even if under PBR and more stringent than a current federal rule. Additionally, based on the commission's previous experience with review of OGS registrations and with Region's experience with OGS, the commission determines that more extensive parametric monitoring is needed for the highest effectiveness of control, as the highest effectiveness of control and the extensive use of such control are typically claimed to keep relatively large OGS operations under PBR emission limits; therefore, the commission determines that the more extensive parametric monitoring is needed for practical enforceability.

The commission has revised the requirement to clarify how and when glycol dehydration control needs to be addressed. If a remote site with no close receptors does not need to capture and condense BTEX and water off the reboiler process vent to meet emission limitations then condenser monitoring is not required. Where control is necessary the to meet emission limitations a weekly check and record is required.

The TCEQ changes the rule in response to this comment for clarity and resolution.

All monitoring and controls are voluntary in the final OGS PBR. If a control is needed to meet the emission impacts or limitations of the PBR, then the once weekly monitoring of the temperature of air condenser exhaust along with other parameters as listed in Table 8, Process Units, Glycol Dehydration Units apply. Continuous temperature monitoring is not required over the once weekly monitoring of air condenser exhaust temperature. For the PBR where a condensor is necessary to meet emission limitations and the claimed control efficiency is based on the GRI-GlyCalc program, the commissions changes the rule to require a spot check of the temperature is approved with the weekly time frame as suggested in this comment.

TXOGA, Devon, GPA, Noble, ExxonMobil, and Anadarko "Propose default efficiency of 50 percent for cyclic service heaters/reboilers without requiring additional monitoring per Table 7. Records of operational monitoring and testing records: For process heaters, boilers, reboilers, and heater treaters that do NOT serve as emission control devices, or where waste gas is utilized in the fuel system, the maximum annual runtime of 8,760-hours may be used to calculate emissions in lieu of runtime tracking. For process heaters, boilers, reboilers, and heater treaters that DO serve as emission control devices, a default destruction efficiency factor of up to 50 percent may be claimed with no additional runtime monitoring or testing.

Devon requested clarification on Table 8: Monitoring and Records Demonstrations Control Devices - Flare Monitoring. "The proposed PBR and standard permit need to clarify that the general provisions of §111.111(4) do not apply to unmanned sites with respect to keeping a daily flare log. Since the proposed PBR and standard permit would result in more flares being installed at OGS, the TCEQ must ensure that there are no unintended consequences of the §111.111(4) rules requiring "daily notation in the flare operation log that the flare was observed including the time of day and whether or not the flare was smoking." It is not possible to keep a daily flare log at unmanned sites and should therefore be excluded from §111.111 requirements."

The commission does not change rule language in response to this comment. The requirements of §111.111(4) apply to every gas flare in the state regardless of their authorization, and is within the scope of this rulemaking. Section 111 apply to unmanned sites. The commission is not aware of existing unmanned OGS with flares that have had issues with the §111 items specified in the comment. The commission's experience is that OGS with flares are usually large enough sites to be manned or at least be checked on a daily basis. Additionally, the commission is aware of other types of checks that some OGS perform on a daily basis at unmanned sites.

Encana commented on Table 8 PBR §106.352 and Standard Permit- Category -Control Devices - Flare Monitoring. "Basic monitoring requires the flare and pilot flame to be continuously monitored by a thermocouple or an infrared monitor.,, 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. This requirement does not consider small, remote facilities that have no electricity and are unmanned. Operators should be given the option to continuously record presence of pilot light or to install auto-igniters and log presence of pilot light when operators visit the facility during their rotation or at a frequency of once every month."

In response to this comment and other comments, the commission re-evaluates the requirements for continuous monitoring for flares. Based on the commission's current knowledge including knowledge from an ongoing flare study, the commission determines that a significant number of flares in the state may not be operating at the efficiency claimed. Through Regions, the commission is also aware that some OGS have facilities that are called flares. For example, these may actually only are pipes without flare tips, without continuous pilots, etc. Additionally, NSPS §60.18 requirements for flares are well established and are typically even used to address flare requirements even if a given new or existing flare is not subject to NSPS §60.18. Also, testing and continuous monitoring of waste gas flow rates for flares in lieu of continuous monitoring (not flow rate monitoring) at OGS is difficult and expensive. Therefore, the commission determines that continuous monitoring for flares is necessary as part of demonstration of compliance with the OGS PBR rule.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko requests clarification that "this only applies to reference method testing, Current TCEQ Sampling Procedure Manual is incomplete and unsigned, 3 one-hour runs is not necessary, 3 30-minute runs are sufficient under the current rules. 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 EPA Reference

Methods. Sampling shall occur using at a minimum three thirty minute test runs and then averaged to demonstrate compliance with the limits of this PBR. Any deviations from those procedures must be approved in writing by the TCEQ Regional Director or his designee prior to sampling."

The commission believes the procedures manual and reference method provide a sound basis and approach for adequate sampling. One hour runs have been standard practice for several decades. There are situations where shorter or longer sampling times and deviations from prescribed methods may be necessary or appropriate and the rule allows the TCEQ Region to approve those changes. Therefore, the commission does not change the rule in response to this comment.

One individual asked "if testing methods need to be accredited by the TCEQ? What expertise will be used to determine the accreditation? Will laboratories need to be TCEQ accredited? What proven industry standards or models will be referenced in determining appropriate protocols? Will the TCEQ-approved protocols, i.e., sampling, testing, etc., be listed? Throughout the document there are references to VOCs and sulfur, is there a list of specific analysis of primary concern to the TCEQ?"

The commission does not change the rule in response to this comment. As included in Table 7, and following over 20 years of permit compliance guidelines, all sampling methods and protocols are expected to follow appropriate EPA Reference Methods and the TCEQ Sampling Procedures Manual. Particular

methods, protocols, and issues are confirmed at the pretest meetings with Regional offices, and variations in standardized methods must be approved in writing.

SWEPI commented that, "The current language in Table 7 suggests that sampling ports and platforms be incorporated into the design of all exhausts stacks, implying all also their incorporation of all existing exhaust stacks. However, costs associated with accessibility and associated OSHA regulations for testing existing facilities are significant. Facilities where grates, catwalks, rails, and ladders are needed for testing equipment in existing facilities can be over $50,000 for each glycol vent or engine exhaust. These costs are large relative to expected emissions reductions and were not included in the fiscal analysis. Although it was mentioned in the fiscal analysis that it "could require future retrofitting of existing facilities to meet emissions limitations," the language in Table 7 concerning sampling ports and platforms should be changed to state that these actions should only be performed in new facilities or when future modifications are expected."

The commission respectfully declines to change sampling ports and platforms language for testing of engines and turbines because testing of engines and turbines was required before the new OGS rules and acceptable stack testing protocol for testing of engines and turbines has already been established. The commission does not anticipate requesting testing for engines and turbines for which testing in not specified or required in the new OGS rules. Additionally, the commission addresses testing requirements for control devices in other responses

to comments, and testing is no longer required under the OGS PBR rule unless specified by the rule and is based on the level of control claimed. In response to all comments received, the commission believes that the OGS PBR rule overall clearly indicates whether or not testing will be required for existing facilities.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko requested clarification that "a pretest meeting with the Regional office only applies to reference method testing and that the pre-test meeting does not apply to engines. This is burdensome not only to the operators but also to the TCEQ for the thousands of tests each year with no environmental benefit. Resource issue for TCEQ (10,000 notices/year), Operational limitations (not always time to schedule test), Notifications should only apply to NSPS/NESHAP testing requirements."

The commission changes and clarifies the language in response to this comment and other comments. The requirements are re-evaluated for when monitoring and testing is required under the OGS PBR and is addressed in response to other comments. Performance testing, if required as specified in the PBR rule, should follow standard procedures and Regional offices should be provided an opportunity to hold a pretest meeting to discuss methods and reporting of results. Except for engine testing, the PBR does not require more than initial testing. Periodic evaluation of engines does not require a pretest meeting unless warranted by the Regional director due to issues with specific OGS engines (e.g., issues with compliance at a particular location; e.g., issues with a particular make and model of engine). The proposed PBR rule allows anything done to comply

with other federal or states rule to also be used in order to minimize any additional cost and recordkeeping to industry. Also, not all engines regulated by the OGS PBR are addressed by the regulations mentioned in the comments. The commission does believe that testing in the OGS PBR has environmental benefit, as the commission determines that testing, if required, is part of ensuring practical enforceability, including demonstration of compliance with emission limits based on an emissions impacts evaluation.

TXOGA, Devon, GPA, Noble, Exxon Mobil, and Anadarko requested clarification to "determine if it is necessary to verify composition "at any point in the process"? Should only be needed for emissions calculations where required. They proposed rule language of "Reports necessary to verify composition (including hydrogen sulfide (H_2S) at any point in the process. Maintain composition records at appropriate points within the process as needed for emissions calculations.""

The commission has not changed the rule in response to the comment. Composition of the material should only be verified at points that are integral to estimating emissions. For example, if there is not a glycol dehydrator at the site, then it is un-necessary to have a material composition for this point. However, if you do have a glycol dehydrator, it is very important for accurately estimating emissions from the dehydrator (that is, the inlet to a glycol unit absorber tower is a point in the process for sampling for testing). A representative analysis can be used if it meets the defined criteria.

El Paso requested "Please consider revising the requirement to test "any turbine" to "any turbine (excluding microturbines)." El Paso employs small Capstone microturbines at some facilities that do not lend themselves well to emissions testing due to their exhaust system design. These microturbines have the potential to emit on, the order of less than 1 tpy of any pollutant. Alternatively, please consider a *de minimis* level for turbines (e.g., "Any turbine> 1 MW)."

The commission respectfully declines to change the rule in response to this comment. Due to high exhaust flow and pollutant concentrations, turbines can represent large emission sources even at 1 MW. The TCEQ routinely works with permit holders who cannot meet aspects of EPA test methods such as Test Method 1 to design a testing protocol that achieves a valid test. It is the TCEQ's intent that small turbines such as the Capstones be tested according to the procedures of EPA Test Methods as best possible. Engines commonly have the small issues as these smaller turbines and the TCEQ has routinely worked with the testing company to come up with a valid methodology.

SUBCHAPTER O: OIL AND GAS

[§106.352]

STATUTORY AUTHORITY

The repeal of this section is adopted 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 adopted 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 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 Hydrogen Sulfide, lb/hr	Minimum 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 adopted 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 adopted 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 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 Handling and Production Facilities ~~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 with the following conditions: ~~. The following restrictions apply:~~

(1) The requirements in subsections (a) - (k) of this section are applicable only for new projects and related facilities located in the Barnett Shale (Archer, Bosque, Clay, Comanche, Cooke, Coryell, Dallas, Denton, Eastland, Ellis, Erath, Hill, Hood, Jack, Johnson, Montague, Palo Pinto, Parker, Shackelford, Stephens, Somervell, Tarrant, and Wise Counties) on or after April 1, 2011. For all other new projects and related facilities, subsection (l) of this section is applicable until January 5, 2012, after which subsections (a) - (k) of this section apply in all counties of the state.

(2) ~~(1)~~ Only one Oil and Gas Handling and Production Facilities permit by rule (PBR) for an oil and gas site (OGS) may be claimed or registered for each combination of dependent facilities ~~site~~ and authorizes all facilities in sweet or sour service. This section may not be used if operationally dependent ~~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 combination of dependent facilities ~~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;~~

(3) ~~(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 laws or regulations. Emissions that exceed the limits in this section are not authorized and are violations ~~of the PBR~~.

(4) ~~(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, day-care, hospital, business, or place of worship at the time this section is registered. A residence is a structure primarily used as a permanent dwelling. A business is a structure that is occupied for at least 8 hours a day, 5 days a week, and does not include

businesses who are handling or processing materials as described in subsection (a) of this section. 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) An OGS is defined as all facilities which meet each of the following:

(A) Located on contiguous or adjacent properties;

(B) Under common ~~interest and~~ control of the same person (or persons under common 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) A project ~~For purposes of claim or registration~~ under this section is defined as the following and must meet all requirements of this section prior to construction or implementation of changes. ~~must be met.~~

(A) Any new facility or new group of operationally dependent ~~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) Physical changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously certified emission limits; or ~~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) Operational changes to existing authorized facilities or group of facilities at an OGS which increase the potential to emit over previously certified emission limits. ~~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 registration under this section ~~ensuring protection of public health and welfare and demonstrating compliance with applicable ambient air standards and effects screening levels~~, the following facilities shall ~~must~~ be ~~met~~ included:

(A) All facilities or groups of facilities at an OGS which are operationally dependent on each other; ~~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) Facilities must be located within a 1/4 mile of a project emission point, vent, or fugitive component, except for those components excluded in subsection (b)(6)(C) of this section. ~~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.~~

(C) If piping or fugitive components are the only connection between facilities and the distance between facilities exceeds 1/4 mile, then the facilities are considered separate for purposes of this registration;

(D) The boundaries of the registration become fixed at the time this section is claimed and registered. No individual facility may be authorized under more than one registration;

(E) Any facility or group of facilities authorized under an existing PBR registration which is operationally dependent on a project must be revised to incorporate the project. 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 subsections (i) and (k) of this section (the protectiveness review and planned MSS requirements) and otherwise retain their existing authorization; and

(F) 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); 15 tpy of particulate matter with less than 10 microns (PM_{10}); 10 tpy of particulate matter less than 2.5 microns ($PM_{2.5}$); and 25 tpy of volatile organic compounds (VOC), sulfur dioxide (SO_2), hydrogen sulfide (H_2S), or any other air contaminant except carbon dioxide, water, nitrogen, methane, ethane, hydrogen, and oxygen.

~~(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.~~

(7) For purposes of all previous claims of this section (or any previous version of this section) where no project is occurring:

(A) existing authorized facilities, or group of facilities, at an OGS must meet only subsection (i) of this section no later than January 5, 2012; and

(B) submit a notification in accordance with subsection (f) of this section ~~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.~~

(8) For purposes of ensuring protection of public health and welfare and demonstrating compliance with applicable ambient air standards and effects screening levels (ESLs), the impacts analysis as specified in subsection (k) of this section must be completed.

(A) All impacts analysis must be done on a contaminant-by-contaminant basis for any net project increases. If a claim under this section is only for planned MSS under subsection (i) of this section, the analysis shall evaluate planned MSS scenarios only.

(B) Hourly and annual emissions shall be limited based on the most stringent of subsections (g), (h), or (k) of this section.

(c) Authorized Facilities, Changes, and Activities.

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

(A) A project ~~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) The following projects do not require registration, but must comply with best management practices (BMP) in subsection (e) of this section, compliance demonstrations in subsections (i) and (j) of this section, and must be incorporated into the registration at the next revision or certification: ~~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) Addition of any piping, fugitive components, any other new facilities, that increase actual emissions less than or equal to 1.0 tpy VOC, 5.0 tpy NO_X, 0.01 tpy benzene, and 0.05 tpy H_2S over a rolling 12-month period; ~~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) Changes to any existing facilities that increase certified emissions less than or equal to 1.0 tpy VOC, 5.0 tpy NO_X, 0.01 tpy benzene, and 0.05 tpy H_2S over a rolling 12-month period; ~~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) Total increases over a rolling 60-month period of time that are less than or equal to 5.0 tpy VOC or NO_X, 0.05 tpy benzene, or 0.1 tpy H_2S; ~~the fugitive components or other new facilities must meet the applicable requirements of subsections (e) and (j) of this section; and~~

(iv) Addition of any new engine rated less than 100 horsepower (hp); or ~~these facilities and changes shall be incorporated at the next revision or update to a registration or certification under this section.~~

(v) Replacement of any facility if the new facility does not increase the previous actual or certified emissions.

(C) For facilities authorized under §116.111 of this title, only records of MSS as specified in this section must be kept and this section may only be used for planned MSS for the facility types specified in this section. ~~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 authorizations ~~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 commission may deny an application for registration under this section for the following reasons: ~~good cause.~~

(A) Failing to meet the requirements of this PBR;

(B) Misrepresenting or failing to disclose fully all relevant facts in obtaining the authorization; or

(C) Being indebted to the state for fees, payment of penalties, or taxes imposed by the statutes or rules within the commission's jurisdiction.

(D) A denial for good cause under this section constitutes a final commission action.

(4) This paragraph covers groups of facilities typically associated with wellheads, pump-jacks, Christmas trees, metering stations, and other similar facilities handling or containing crude oil, condensate, natural gas, or a mixture of these materials (examples include, but are not limited to, stripper/marginal wells producing up to 10 barrels of oil equivalent per day, natural gas up to 60,000 cubic feet per day, or high pressure gas wells). The following projects and facilities are authorized and must only comply with subsections (e)(1), (e)(2), and applicable portions of subsection (j) of this section:

(A) Claims under this paragraph must include all facilities or groups of facilities at an OGS which are operationally dependent on each other and located within a 1/4 mile of a project emission point, vent, or fugitive component. If piping or fugitive components are the only connection between facilities and the distance between facilities exceeds 1/4 mile, then the facilities are considered separate for purposes of this paragraph.

(B) A site-wide combination of engines which meet the following:

(i) Up to 450 hp if fueled by sweet gas;

(ii) Up to 100 hp if fueled by sour gas containing not more than 10,000 parts per million by weight (ppmw) H_2S; or

(iii) Up to 20 hp fueled by sour gas containing more than 10,000 ppmw but not more than 50,000 ppmw H_2S.

(C) For any one of the following combinations of facilities:

(i) Only piping and fugitive components handling liquids or gas up to a maximum of four pump seals; four open-ended lines; and any combination of valves, flanges, and connectors, or meter runs totaling 225 components;

(ii) Only piping and fugitive components handling natural gas up to a maximum of any combination of valves, flanges, and connectors, or meter runs totaling 720 components; or

(iii) Separators used solely to separate crude oil, condensate and natural gas (which are routed directly to a sales pipeline) from produced water. Tanks used and handling only produced water up to 1,205 barrels per day. All associated piping and fugitive components up to a maximum of five pump seals; five open-ended lines; and any combination of valves, flanges, and connectors, or meter runs totaling 150 components.

(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, pressure relief valves, pipe flanges and connectors, pumps, compressors, stuffing boxes, instrumentation and meters, natural gas driven pneumatic pumps, and other similar devices with seals that separate process and waste material from the atmosphere and the associated piping; ~~seals, instrumentation, and associated piping;~~

(B) separators, including all gas, oil, and water physical separation units; ~~pumps and meters;~~

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

~~(D) condensers;~~

(C) ~~(E)~~ treatment and processing equipment, including heater-treaters, methanol injection, glycol dehydrators, molecular or mole sieves, amine sweeteners, H_2S scavenger chemical reaction vessels for sulfur removal ~~SulfaTreat(R)~~, and iron sponge units;

(D) ~~(F)~~ cooling towers and associated heat exchangers;

(E) ~~(G)~~ gas recovery units, including cryogenic expansion, absorption, adsorption, heat exchangers and refrigeration units;

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

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

(H) ~~(J)~~ surface support facilities associated with underground storage of gas or liquids ~~and associated surface support facilities~~;

(I) ~~(K)~~ truck loading equipment;

(J) ~~(L)~~ control equipment, including vapor recovery systems, glycol and amine reboilers, condensers, flares, vapor combustors, and thermal oxidizers; and

(K) ~~(M)~~ temporary facilities used for planned maintenance, and temporary control devices for planned startups 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 be 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); and

(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 project ~~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, paragraphs (1) - (5) of this subsection ~~the following~~ shall be met as applicable. These requirements are not applicable to existing, unchanging facilities. Equipment design and control device requirements listed in paragraphs (6) - (12) of this subsection only apply to those that are chosen by the operator to meet the limitations of this section.

(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 operator ~~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) Compliance with manufacturer's specifications and recommended programs applicable to equipment performance and effect on emissions, or alternatively, an owner or operator developed maintenance plan for such equipment that is consistent with good air pollution control practices;

(B) cleaning and routine inspection of all equipment; and

(C) replacement and repair of equipment on schedules which prevent equipment failures and maintain performance.

(2) Any 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: ~~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.~~

(A) any fugitive components that are used for isolation and/or safety purposes may be located at 1/2 of the width of any applicable easement;

(B) any 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 facilities which are located less than 50 feet from a property line or receptor when constructed and previously authorized. If modified or replaced the operator shall consider, to the extent that good engineering practice will permit, moving these facilities to meet the 50-foot requirement. Replacement facilities must meet all other requirements of this section.

(3) Engines and turbines shall meet the emission and performance standards listed in Table 6 in subsection (m) of this section and the following requirements: ~~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) liquid 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 the engine is operated less than 876 hours per rolling 12-month period; ~~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) engines and turbines used for electric generation more than 876 hours per rolling 12-month period are authorized if no reliable electric service is readily available and Table 6 in subsection (m) 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 standard permit registration requirements) and the emissions shall be included in the registration under this section; ~~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) all applicable requirements of Chapter 117 of this title (relating to Control of Air Pollution from Nitrogen Compounds); and ~~existing, immovable, fixed OGS facilities which were constructed and previously authorized, even if modified.~~

(D) all applicable requirements of 40 CFR Parts 60 and 63.

(E) Compression ignition engines that are rated less than 225 kilowatts (300 hp) and emit less than or equal to the emission tier for an equivalent-sized model year 2008 non-road compression ignition engine located at 40 CFR §89.112, Table 1 are authorized.

(4) Open-topped tanks or ponds containing VOCs or H_2S are allowed up to a potential to emit equal to 1.0 tpy of VOC and 0.1 tpy of H_2S. ~~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) The following shall apply to all fugitive components at the site associated with the project: ~~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.~~

(A) All components shall be physically inspected quarterly for leaks.

(B) All components found to be leaking shall be repaired. Every reasonable effort shall be made to repair a leaking component. All leaks not repaired immediately shall be tagged or noted in a log. At manned sites, leaks shall be repaired no later than 30 days after the leak is found. At unmanned sites, leaks shall be repaired no later than 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 shutdown.

(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, gauging, loading, unloading, or planned maintenance activities.

(D) 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. Underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

(6) When leak detection and repair (LDAR) fugitive monitoring is chosen by the operator, Table 9, in subsection (m) of this section, shall apply. In addition, all components shall be physically inspected at least weekly by operating personnel walk-through. ~~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) Tanks and vessels that utilize a paint color to minimize the effects of solar heating (including, but not limited to, white or aluminum): ~~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) 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); ~~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) paint shall be applied according to paint producers recommended application requirements if provided and in sufficient quantity as to be considered solar resistant; ~~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) paint coatings shall be maintained in good condition and will not compromise tank integrity. Minimal amounts of rust may be present not to exceed 10% of the external surface area of the roof or walls of the tank and in no way may compromise tank integrity. Additionally, 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 identification and/or aesthetics; ~~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) for tanks and vessels purposefully darkened to create the process reaction and help condense liquids from being entrained in the vapor or are 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. ~~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.~~

(8) All emission estimation methods including but not limited to computer programs such as GRI-GLYCalc, AmineCalc, E&P Tanks, and Tanks 4.0, must be used with monitoring data generated in accordance with Table 8 in subsection (m) of this section where monitoring is required. All emission estimation methods must also be used in a way that is consistent with protocols established by the commission or promulgated in federal regulations (NSPS, NESHAPS). Where control is relied upon to meet subsection (k) of this section, control monitoring is required.

(9) Process reboilers, heaters, and furnaces that are also used for control of waste gas streams:

(A) may claim 50% to 99% destruction efficiency for VOCs and H_2S 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;

(B) 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;

(C) In systems where the combustion device is designed to cycle on and off to maintain the designed heating parameters, and may not fully utilize the waste gas stream, records of run time and enhanced monitoring are required to claim any run time beyond 50%.

(10) Vapor recovery Units (VRUs) may claim up to 100% control. The control efficiency is based on whether it is a mechanical VRU (mVRU) or a liquid VRU (lVRU). The VRUs must meet the appropriate design, monitoring, and recordkeeping in Table 7 and Table 8 in subsection (m) of this section.

(11) Flares used for control of emissions from production, planned MSS, emergency, or upset events may claim design destruction efficiency of 98%. 99% may be claimed for destruction of compounds containing only carbon, hydrogen, and oxygen with no more than three carbon atoms. All flares 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 except where only field gas is available and it is not sweetened at the site; and

(G) flares shall be designed for and operated with no visible emissions, except for periods not to exceed at total of five minutes during any two 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.

(12) Thermal oxidation and vapor combustion control devices:

(A) may claim design destruction efficiency from 90% to 99.9% for VOCs and H_2S depending on the design and the level of monitoring and testing applied;

(B) 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;

(C) 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%;

(D) 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;

(E) 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.

(f) Notification, Certification, and Registration Requirements ~~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) For all previous claims of this section (or any previous version of this section) existing authorized facilities, or group of facilities, identified in subsection (b)(7) of this section must submit a notification no later than January 1, 2013. Facilities or groups of facilities which meet subsection (c)(4) of this section do not have to meet the following notification requirements: ~~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) For actively operating facilities which have never been registered with the commission, submit updated Core Data and basic identifying information (previously claimed historical versions of this section and lease name or well numbers as provided to the Texas Railroad Commission) through ePermits using the "APD OGS Historical Notification." ~~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) For those facilities which have previously registered with the commission and updates are needed to the commission's Central Registry (CR), submit a hard copy of a Core Data Form with an attachment listing identifying information (previously claimed historical versions of this section and lease name or well numbers as provided to the Texas Railroad Commission). If no updates to CR are required, no further action is needed. ~~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.~~

(C) No fee is required for this notification.

(2) If no other changes, except for authorizing planned MSS, occur at an existing site under this section, or any previous version of this section, the following apply no later than January 5, 2012: ~~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.~~

(A) Records demonstrating compliance with subsection (i) of this section must be kept;

(B) If the existing OGS is certified, an addendum to the OGS certification may be filed using Form APD-CERT. No fee is required for this updated certification; and

(C) Planned MSS does not require registration if no other project is occurring, and shall be incorporated at the next revision or update to a registration under this section after January 5, 2012.

(3) For facilities authorized under §116.111 of this title, only records of MSS as specified in this section must be kept. Planned MSS shall be incorporated into the permit at the next permit renewal or amendment after January 5, 2012. ~~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) Prior to construction or implementation of changes for any project which meets this section, a notification shall be submitted through the ePermits system. This notification shall include the following: ~~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 (l), 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.~~

(A) Identifying information (Core Data) and a general description of the project must be submitted through ePermits (or if not available, hard-copy) using the "APD OGS New Project Notification."

(B) A fee of $25 for small businesses (as defined in §106.50 of this title (relating to Registration Fees for Permits by Rule), or $50 for all others must be submitted through the commission's ePay system.

(5) For any registration which meets the emission limitations of Level 1 as required in subsection (g) of this section: ~~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) Within 180 days after start of operation or implemented changes (whichever occurs first), the facilities must be registered through ePermits form "APD OGS PBR Level 1 and 2 Registration" (or if not available, submittal of hard-copy). ~~meet specifications for minimum heating values of waste gas, maximum tip velocity, and pilot flame monitoring found in 40 CFR §60.18;~~

(B) This registration shall include a detailed summary of maximum emissions estimates based on: ~~if necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible;~~

(i) site-specific or defined representative gas and liquid analysis;

(ii) equipment design specifications and operations;

(iii) material type and throughput;

(iv) other actual parameters essential for accuracy for determining emissions; and

(v) documentation demonstrating compliance with all applicable requirements of this section.

(C) The fee for this registration shall be $25 for small businesses, as defined in §106.50 of this title, or $175 for all others. ~~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) For any registration which meets the emission limitations of Level 2 as required in subsection (h) of this section: ~~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.~~

(A) Within 90 days after start of operation or implemented changes (whichever occurs first), the facilities must be registered through ePermits form "APD OGS PBR Level 1 and 2 Registration" (or if not available, submittal of hard-copy).

(B) This registration shall include a detailed summary of maximum emissions estimates based on:

(i) site-specific or defined representative gas and liquid analysis;

(ii) equipment design specifications and operations;

(iii) material type and throughput; and

(iv) other actual parameters essential for accuracy for determining emissions and compliance with all applicable requirements of this section.

(C) The fee for this registration shall be $75 for small businesses (as defined in §106.50 of this title) or $400 for all others.

(7) Certified registrations or certifications are required 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 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.

(B) If a project or registration includes control for reductions, limited hours, throughput, and materials or other operational limitations which are less than the potential to emit, and if modeling is used to demonstrate compliance with subsection (k) of this section.

(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) or relies on controls to comply with any state or federal regulation.

(D) For projects which resolve compliance issues and are the result of a commission or United States Environmental Protection Agency order.

(8) If the ePermits system is not available for more than 24 hours or not otherwise accessible, hard copies of notifications, registrations, or certifications may be submitted by first-class mail.

(9) If emissions increase at an OGS to a level where it exceeds its current

authorization, either through a change in production or addition of facilities, the site may claim and register its facilities under the applicable authorization (Level 1 or Level 2 PBR or Standard Permit) as follows:

(A) Within 90 days from the initial notification of construction of an oil and gas facility, a registration can update the authorization mechanism by submitting a revision to the PBR or an application for a standard permit; and

(B) Within 90 days of the change of production or installation of additional equipment, a revision to the PBR or an application for a standard permit has been submitted.

(g) Level 1 Requirements ~~post-construction registration~~. Total maximum estimated emissions shall meet the most stringent of the following. All emissions estimates must be based on representative worst-case operations and planned MSS activities.

(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.

(2) Emissions must meet the limitations established in subsection (k) of this section. ~~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) Maximum emissions are limited to less than the following after any operator limitations or controls: ~~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:~~

Figure 1: 30 TAC §106.352(g)(3)

Maximum Emission Rates

Air contaminant	steady-state lb/hr	< 30 psig periodic lb/hr up to 150 hr/yr	≥ 30 psig periodic lb/hr up to 150 hr/yr	Total tpy
Total VOC*				15
Total crude oil or condensate VOC*	100	145	318	
Total natural gas VOC*	204	750	1500	
Benzene	1.95	7	15.4	2.8
Hydrogen sulfide	4.7	5.1	9.8	20.6
Sulfur dioxide	47	93.2		25
Nitrogen oxides	43.2			100
Carbon monoxide	45			100
PM_{10} and $PM_{2.5}$	10			5

* VOC is defined in §101.1 of this title (relating to General Definitions) and

does not include methane and ethane

~~(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 commission 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 Requirements ~~Preconstruction Registration~~. If the requirements of ~~the~~ Level 1 ~~Notification~~ cannot be met, then the conditions of this subsection must be followed. Total maximum estimated registered or certified emissions shall meet the most stringent of the following. All emissions estimates must be based on representative worst-case operations and planned MSS activities.

(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) Emissions must meet the limitations established in subsection (k) of this section. ~~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) Maximum emissions are limited to less than the following after any operator limitations or controls: ~~Certifications to establish enforceable emission limits shall be submitted in the following circumstances.~~

Figure: 30 TAC §106.352(h)(3)

Maximum Emission Rates

Air contaminant	steady-state lb/hr	< 30 psig periodic lb/hr up to 300 hr/yr	≥ 30 psig periodic lb/hr up to 300 hr/yr	Total tpy
Total VOC*				25
Total crude oil or condensate VOC*	100	145	318	

Total natural gas VOC*	356	750	1500	
Benzene	3.35	7	15.4	4.8
Hydrogen sulfide	6	6	9.8	25
Sulfur dioxide	63	93.2		25
Nitrogen oxides	54.4			250
Carbon monoxide	57			250
$PM_{2.5}$	12.7			10
PM_{10}	12.7			15

* VOC is defined in §101.1 of this title and does not include methane and ethane

~~(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, Startup 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; and

(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 of the activity.

(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.~~

(D) ~~(F)~~ Turbine hot section swaps.

(E) ~~(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 startups 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 result in no greater than 4 lb/hr of natural gas emissions ~~not result in emissions~~; and

(C) emissions which result from the subsequent compressor startup 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. Other requirements, including but not limited to, federal recordkeeping or testing requirements, can be used to demonstrate compliance if the other requirements are at least as stringent as the associated requirements in the Tables 7 and 8 in subsection (m) of this section. Any documentation that is already being kept for other purposes will suffice for demonstrating requirements. If a control or method is not relied upon for emission reductions, then the associated sampling, monitoring, and records are not applicable.

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

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

(k) Emission limits based on impacts evaluation.

(1) All impacts evaluations must be completed on a contaminant-by-contaminant basis for any net emissions increases resulting from a project and must meet the following as appropriate: ~~All emissions estimates must be based on representative worst-case operations and planned MSS activities.~~

(A) Compliance with state or federal ambient air standards shall be demonstrated for NO_2, SO_2, and H_2S at any property-line within 1/4 mile or 1/2 mile of a project under subsection (g) (Level 1) or subsection (h) (Level 2) of this section, respectively.

(B) Compliance with hourly ESLs for benzene and annual ESL for benzene, shall be demonstrated at the nearest receptor within 1/4 mile or 1/2 mile of a project under subsection (g) (Level 1) or subsection (h) (Level 2) of this section, respectively.

(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 Web page.

(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 or ~~and~~ federal ambient air quality standard.

(3) Impacts evaluations are not required under the following cases: ~~Evaluation of emissions shall meet the following.~~

(A) If there is no receptor within 1/4 mile of a Level 1 registration, or 1/2 mile of a Level 2 registration, no further ESL review is required. ~~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) If there is no property line within 1/4 mile of a Level 1 registration, or 1/2 mile of a Level 2 registration, no further ambient air quality standard review is required. ~~The maximum predicted concentration or rate must not exceed a state or federal ambient air standard or ESL. A site-wide analysis including all on-property sources should be conducted. This demonstration must use the maximum predicted concentration to compare to the applicable short- and long-term standards or ESL. If the total quantity of emissions are less than the following rates, no additional analysis or demonstration of the specified air contaminant is required:~~

~~(i) 9 lb/hr 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.~~

(C) If the project total emissions are less than any of the following rates, no additional analysis or demonstration of the specified air contaminant is required:

Figure: 30 TAC §106.352(k)(3)(C)

Project Total Air Contaminant

Emission Rates for Which No Impacts Review Required

Air contaminant	**lb/hr**
Benzene	0.039
Hydrogen sulfide	0.025
Sulfur dioxide	2
Nitrogen oxides	4

(4) Evaluation of emissions shall meet the following. ~~must comply with one of the methods listed with no changes or exceptions:~~

(A) For all evaluations of NO_X to NO_2, a conversion factor of 0.20 for 4-stroke rich and lean-burn engines and 0.50 for 2-stroke lean-burn engines may be used. ~~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) The maximum predicted concentration or rate at the property boundary or receptor, whichever is appropriate, must not exceed a state or federal ambient air standard or ESL. ~~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.~~

(5) The impacts analysis shall be based on the following facility emissions.

(A) The following shall be met for ESL reviews:

(i) If a project's air contaminant maximum predicted concentrations are equal to or less than 10% of the appropriate ESL, no further review is required.

(ii) If a project's air contaminant maximum predicted concentrations combined with project increases for that contaminant over a 60-month period after the effective date of this revised section are equal to or less than 25% of the appropriate ESL, no further review is required.

(iii) In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1/4 mile of a project requiring registration under this section shall be evaluated.

(B) The following shall be met for state and federal ambient air quality standard reviews:

(i) If a project's air contaminant maximum predicted concentrations are equal to or less than the significant impact level (also known as *de minimis* impact in Chapter 101 of this title (relating to General Air Quality Rules)), no further review is required;

(ii) In all other cases, all facility emissions at an OGS, regardless of authorization type, located within 1/4 mile of a project requiring registration under this section shall be evaluated.

(6) Evaluation must comply with one of the methods listed with no changes or exceptions.

(A) Tables.

(i) Emission impact Tables 2 - 5F in subsection (m) of this section, may be used in accordance with the limits and descriptions in Table 1 in subsection (m) of this section.

(ii) Values in Tables 2 - 5F in subsection (m) of this section may be used with linear interpolation between height and distance points. A distance of less than 50 feet or greater than 5,500 feet may not be used. Release heights may not be extrapolated beyond the limits of any table and instead the minimum or maximum height will 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 (e)(2) 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) Existing, Unchanged Facilities and Projects Before Effective Date. The requirements in this subsection are applicable to existing unchanged facilities and new or changing facilities as specified in subsection (a)(1) of this section. 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 subsection are met. This subsection 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 §106.492 and §106.512 of this title (relating to Flares, and Stationary Engines and Turbines, respectively). Oil and gas facilities which are authorized under historical standard exemptions and remain unchanged maintain that authorization and the remainder of this subsection does not apply.

(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 subsection shall not exceed 25 tpy each of SO_2, all other sulfur

compounds combined, or all VOCs combined; and 250 tpy each of NO_X and CO. 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) 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, where the total emission rate as H_2S, lb/hr, and minimum vent height (feet), and other **v**alues may be interpolated**:**

(A) 0.27 lb/hr at 20 feet;

(B) 0.60 lb/hr at 30 feet;

(C) 1.94 lb/hr at 50 feet;

(D) 3.00 lb/hr at 60 feet; and

(E) 4.00 lb/hr at 68 feet.

(4) Before operation begins, facilities handling sour gas shall be registered with the commission's Office of Permitting and Registration in Austin using Form PI-7 along with supporting documentation that all requirements of this subsection 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 subsection can begin. If the facilities cannot meet this subsection, 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.

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

Figure: 30 TAC §106.352 (m) ~~(l)~~

Table 1 Emission Impact Tables Limits and Descriptions

Topic	Description	Details
Variables	$E_{MAX\ HOURLY}$	the maximum acceptable hourly (lb/hr) emissions for a specific air contaminant
	$E_{MAX\ ANNUAL}$	the maximum acceptable annual (tpy) emissions for a specific air contaminant
	P	ambient air standard for a specific air contaminant (µg/m^3)
	ESL	current published effects screening level for a specific air contaminant (µg/m^3)
	G	the most stringent of any applicable generic value from the Generic Modeling Results Tables at the emission point's release height and distance to property line (µg/m^3/lb/hr)
	WR_{EPNx}=	weighted ratio of emissions of a specific air contaminant for each EPN divided by the sum of total emissions for all EPNs that emit that contaminant or (E_{EPNx}/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: $E_{MAX\ HOURLY} = ESL/G$
	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: $E_{MAX\ HOURLY} = (WR_{EPN1})\ (P\ /\ G_{EPN1}) + (WR_{EPN2})\ (P\ /\ G_{EPN2}) + \ldots(WR_{EPNx})\ (P\ /\ G_{EPNx})$
	hourly health effects review	emissions are determined by: $E_{MAX\ HOURLY} = (WR_{EPN1})\ (ESL\ /G_{EPN1}) + (WR_{EPN2})\ (ESL/G_{EPN2}) + \ldots..(WR_{EPNx})\ (ESL\ /\ G_{EPNx})$
	annual ambient air standard	emissions are determined by: $E_{MAX\ ANNUAL} = (8760/2000)\ [(WR_{EPN1})\ (P\ /\ 0.08*G_{EPN1}) + (WR_{EPN2})\ (P\ /\ 0.08*G_{EPN2}) + \ldots.\ (WR_{EPNx})\ (P\ /\ 0.08*G_{EPNx})]$
	annual health effects review	emissions are determined by: $E_{MAX\ ANNUAL} = (8760/2000)\ [(WR_{EPN1})\ (ESL\ /0.08*G_{EPN1}]) + (WR_{EPN2})\ (ESL/0.08*G_{EPN2}) + \ldots(WR_{EPNx})\ (ESL\ /\ 0.08*G_{EPNx})]$

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

~~oTopic~~	**~~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 (µg/m^3)~~
	~~ESL~~	~~current published effects screening level for the specific air contaminant (µg/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 (µg/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
2800	53	69	63	50	40	32	31	30	17
2900	50	65	60	48	39	31	30	29	16
3000	48	62	57	46	37	30	29	28	16
3500	37	49	46	38	32	26	25	25	14
4000	30	40	38	32	28	24	23	22	12
4500	25	33	32	28	25	21	20	20	11
5000	22	28	27	24	22	19	18	18	10
5500	19	25	24	21	19	17	17	16	9

Table 3: Flares and Thermal Destruction Devices					
Generic Modeling Results					
Distance	20 ft height	30 ft height	40 ft height	50 ft height	60 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
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
2800	19	19	18	17	16
2900	19	19	17	16	16
3000	18	18	17	16	16
3500	16	16	15	14	14
4000	14	14	13	12	12
4500	13	13	12	11	11
5000	11	11	11	10	10

5500	11	11	10	9	9

~~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: Generic Modeling Results for Blowdowns, Purging, and Pigging

	Generic Modeling Results				
Distance	< 30 psig; 3 ft height	< 30 psig; 10 ft height	< 30 psig; 20 ft height	≥ 30 psig; 6 ft height	≥ 30 psig; 10 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	4304	791	244	51	25
100	4304	791	244	51	25
150	4250	777	244	51	25
200	3621	763	244	51	25
300	2367	750	225	51	25
400	1607	737	225	51	25
500	1156	671	224	51	25
600	871	581	218	48	25
700	682	498	212	44	25
800	551	427	210	40	24
900	456	368	204	36	23
1000	384	320	194	33	21
1100	328	281	182	30	20
1200	284	248	170	28	18
1300	249	221	159	27	17
1400	220	198	147	27	16
1500	196	178	137	27	15
1600	176	162	127	27	14
1700	159	147	118	27	13
1800	145	135	110	27	13
1900	132	124	103	27	13
2000	121	114	96	27	13
2100	112	106	90	27	13
2200	103	98	85	27	13
2300	96	91	80	27	13
2400	90	86	75	27	13
2500	84	81	71	27	13
2600	79	76	68	27	13
2700	74	72	64	26	13
2800	70	68	61	26	13
2900	67	64	58	26	13
3000	63	61	55	25	13
3500	50	48	45	23	13
4000	40	39	37	21	13
4500	34	33	31	19	13

5000	29	28	27	17	12
5500	25	24	23	16	11

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

~~Distance~~	~~8 ft~~	~~10 ft~~	~~12 ft~~	~~14 ft~~	~~16ft~~	~~18ft~~	~~20 ft~~	~~25 ft~~	~~30 ft~~	~~35 ft~~	~~40 ft~~
~~(ft)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(lb/hr)~~	~~(µg/m^3)/(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 5A Engines Less Than or Equal to 250 hp

Generic Modeling Results

Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)
50	97	85	83	81	81	71	58	44	43	36	26
100	97	85	83	81	81	71	58	44	43	36	26
150	97	85	83	81	81	71	58	44	43	36	26
200	93	85	83	81	81	71	58	44	43	36	26
300	92	85	83	81	81	71	58	44	43	36	26
400	91	85	83	81	81	71	58	44	43	36	26
500	88	85	83	81	81	71	58	44	43	36	26
600	80	79	78	78	78	70	56	44	43	36	26
700	78	77	76	76	71	68	52	44	43	36	26
800	76	75	74	74	64	63	47	44	43	36	26
900	74	73	72	72	58	58	45	44	43	36	26
1000	72	71	71	71	53	53	44	43	43	36	26
1100	69	69	69	69	49	49	42	42	41	35	25
1200	66	66	66	65	45	45	40	40	40	35	24
1300	62	62	62	62	42	42	38	38	38	33	23
1400	59	59	59	59	39	39	36	36	36	32	23
1500	56	56	56	56	37	37	34	34	34	30	23
16	53	53	53	53	35	35	32	32	32	29	22

00											
1700	50	50	50	50	33	33	31	31	31	28	22
1800	48	48	48	48	31	31	29	29	29	26	22
1900	46	46	46	46	30	30	28	28	28	25	22
2000	44	44	44	44	28	28	26	26	26	24	21
2100	42	42	42	42	27	27	25	25	25	23	21
2200	40	40	40	40	26	26	24	24	24	22	20
2300	38	38	38	38	25	25	23	23	23	21	20
2400	37	37	37	37	24	24	22	22	22	20	20
2500	36	36	36	36	23	23	22	22	22	20	19
2600	34	34	34	34	22	22	21	21	21	19	19
2700	33	33	33	33	21	21	20	20	20	18	18
2800	32	32	32	32	21	21	19	19	19	18	18
2900	31	31	31	31	20	20	19	19	19	17	17
3000	30	30	30	30	19	19	18	18	18	17	17
3500	26	26	26	26	17	17	16	16	16	15	15
4000	23	23	23	23	15	15	14	14	14	13	13
4500	21	21	21	21	13	13	13	13	13	12	12
5000	19	19	19	19	12	12	11	11	11	11	11
5500	17	17	17	17	11	11	11	11	11	10	10

Table 5B: Engines Greater Than 250 and Less Than or Equal to 500 hp

Generic Modeling Results

Distance (ft)	8 ft height G_{hourly} (µg/m³)/(lb/hr)	10 ft height G_{hourly} (µg/m³)/(lb/hr)	12 ft height G_{hourly} (µg/m³)/(lb/hr)	14 ft height G_{hourly} (µg/m³)/(lb/hr)	16 ft height G_{hourly} (µg/m³)/(lb/hr)	18 ft height G_{hourly} (µg/m³)/(lb/hr)	20 ft height G_{hourly} (µg/m³)/(lb/hr)	25 ft height G_{hourly} (µg/m³)/(lb/hr)	30 ft height G_{hourly} (µg/m³)/(lb/hr)	35 ft height G_{hourly} (µg/m³)/(lb/hr)	40 ft height G_{hourly} (µg/m³)/(lb/hr)
50	60	59	54	43	43	34	34	24	21	20	17
100	60	59	54	43	43	34	34	24	21	20	17
150	60	59	54	43	43	34	34	24	21	20	17
200	60	59	54	43	43	34	34	24	21	20	17
300	60	59	54	43	43	34	34	24	21	20	17
400	60	59	54	43	43	34	34	24	21	20	17
500	60	59	54	43	43	34	34	24	21	20	17
600	57	57	52	41	41	34	34	24	21	20	17
700	52	52	47	38	38	31	31	24	21	20	17
800	47	47	43	34	34	28	28	24	21	20	17
900	42	42	39	31	31	26	26	23	20	20	17
1000	39	39	35	28	28	23	23	21	20	20	17
1100	37	36	32	26	26	23	23	20	20	19	17
1200	35	35	30	25	24	23	23	20	20	18	17
1300	34	34	28	24	23	23	23	20	20	18	16
1400	32	32	26	24	23	23	23	20	20	17	16
1500	31	31	24	23	23	23	23	20	20	16	16
1600	29	29	23	23	23	23	23	19	19	16	16
1700	28	28	23	23	23	23	22	19	19	16	15
1800	27	27	22	22	22	22	22	19	19	16	15
1900	25	25	22	22	22	21	21	18	18	16	15

2000	24	24	22	22	22	21	21	17	17	16	15
2100	23	23	21	21	21	20	20	17	17	16	15
2200	22	22	21	21	21	19	19	17	17	15	15
2300	21	21	20	20	20	19	19	17	16	15	14
2400	21	21	20	20	20	19	18	16	16	15	14
2500	20	20	19	19	19	18	18	16	16	14	14
2600	19	19	19	19	19	18	17	16	16	14	13
2700	18	18	18	18	18	17	17	15	15	14	13
2800	18	18	18	18	18	17	16	15	15	13	13
2900	17	17	17	17	17	16	16	15	15	13	13
3000	17	17	17	17	17	16	15	15	15	13	13
3500	15	15	15	15	15	14	14	13	13	12	11
4000	13	13	13	13	13	13	12	12	12	11	10
4500	12	12	12	12	12	11	11	10	10	10	9
5000	11	11	11	11	11	10	10	10	10	9	9
5500	10	10	10	10	10	9	9	9	9	8	8

Table 5C: Engines Greater Than 500 and Less Than or Equal to 1,000 hp

Generic Modeling Results

Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	26	25	25	25	18	18	17	13	11	11	10
100	26	25	25	25	18	18	17	13	11	11	10
150	26	25	25	25	18	18	17	13	11	11	10
200	26	25	25	25	18	18	17	13	11	11	10
300	26	25	25	25	18	18	17	13	11	11	10
400	26	25	25	25	18	18	17	13	11	11	10
500	26	25	25	25	18	18	17	13	11	11	10
600	26	25	25	25	18	18	17	13	11	11	10
700	26	25	25	25	18	18	17	13	11	11	10
800	24	24	24	24	18	18	17	13	11	11	10
900	23	23	23	23	18	18	17	13	11	11	10
1000	21	21	21	21	17	17	17	13	11	11	10
1100	20	20	20	20	17	17	16	13	11	11	10
1200	18	18	18	18	16	16	16	12	11	11	10
1300	17	17	17	17	15	15	15	12	11	10	10
1400	17	17	17	17	14	14	14	11	11	10	10
1500	17	17	16	16	13	13	13	11	11	10	9
1600	17	17	16	16	13	13	13	11	11	10	9
17	16	16	15	15	13	12	12	11	11	9	9

00											
1800	16	16	15	15	13	12	12	11	11	9	9
1900	15	15	14	14	13	12	12	11	10	9	9
2000	15	15	14	14	13	12	12	11	10	9	9
2100	14	14	13	13	12	12	12	11	10	9	9
2200	14	14	13	13	12	12	12	10	10	9	9
2300	13	13	12	12	12	11	11	10	10	9	8
2400	13	13	12	12	12	11	11	10	9	9	8
2500	12	12	12	12	11	11	11	10	9	9	8
2600	12	12	11	11	11	11	11	10	9	9	8
2700	12	12	11	11	11	10	10	10	9	8	8
2800	11	11	11	11	11	10	10	9	9	8	8
2900	11	11	10	10	10	10	10	9	9	8	8
3000	11	11	10	10	10	10	10	9	9	8	8
3500	9	9	9	9	9	9	9	8	8	7	7
4000	8	8	8	8	8	8	8	7	7	7	6
4500	7	7	7	7	7	7	7	7	6	6	6
5000	7	7	7	7	6	6	6	6	6	6	5
5500	6	6	6	6	6	6	6	6	5	5	5

Table 5D: Engines Greater Than 1,000 and Less Than or Equal to 1,500 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)	G_{hourly} (µg/m^3)/(lb/hr)
50	17	13	12	10	10	10	10	9	8	8	7
100	17	13	12	10	10	10	10	9	8	8	7
150	17	13	12	10	10	10	10	9	8	8	7
200	17	13	12	10	10	10	10	9	8	8	7
300	17	13	12	10	10	10	10	9	8	8	7
400	17	13	11	10	10	10	10	9	8	8	7
500	17	13	11	10	10	10	10	9	8	8	7
600	17	12	11	10	10	10	10	9	8	8	7
700	17	11	11	10	10	10	10	9	8	8	7
800	17	11	11	10	10	10	10	9	8	8	7
900	17	11	11	10	10	10	10	9	8	8	7
1000	17	11	11	10	10	10	10	9	8	8	7
1100	16	11	11	10	10	10	10	9	8	8	7
1200	15	10	10	10	9	9	9	9	8	7	7
1300	15	10	10	10	9	9	9	8	8	7	7
1400	14	10	10	10	9	9	8	8	8	7	7
1500	13	10	10	10	8	8	8	8	8	7	6
1600	12	10	10	10	8	8	8	8	8	7	6
17	12	10	10	10	8	8	8	8	8	7	6

00											
1800	11	10	10	10	8	8	8	8	8	7	6
1900	11	10	9	9	8	8	8	7	7	7	6
2000	10	9	9	9	8	8	8	7	7	7	6
2100	10	9	9	9	8	8	8	7	7	6	6
2200	10	9	9	9	8	8	8	7	7	6	6
2300	9	9	8	8	8	8	8	7	7	6	6
2400	9	9	8	8	7	7	7	7	7	6	6
2500	9	8	8	8	7	7	7	7	6	6	5
2600	8	8	8	8	7	7	7	7	6	6	5
2700	8	8	8	8	7	7	7	7	6	6	5
2800	8	8	7	7	7	7	7	6	6	6	5
2900	8	7	7	7	7	7	7	6	6	6	5
3000	7	7	7	7	7	7	6	6	6	5	5
3500	7	6	6	6	6	6	6	6	5	5	5
4000	6	6	6	6	5	5	5	5	5	4	4
4500	5	5	5	5	5	5	5	5	4	4	4
5000	5	5	5	5	5	5	4	4	4	4	4
5500	5	4	4	4	4	4	4	4	4	4	3

Table 5E: Engines Greater Than 1,500 and Less Than or Equal to 2,000 hp											
Generic Modeling Results											
Distance	8 ft height	10 ft height	12 ft height	14 ft height	16 ft height	18 ft height	20 ft height	25 ft height	30 ft height	35 ft height	40 ft height
(ft)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)	G_{hourly} (µg/m³)/(lb/hr)
50	10	9	8	8	8	7	7	7	6	5	5
100	10	9	8	8	8	7	7	7	6	5	5
150	10	9	8	8	8	7	7	7	6	5	5
200	10	9	8	8	8	7	7	7	6	5	5
300	10	9	8	8	8	7	7	7	6	5	5
400	10	9	8	8	8	7	7	7	6	5	5
500	10	9	8	8	8	7	7	7	6	5	5
600	10	9	8	8	8	7	7	7	6	5	5
700	9	8	8	8	8	7	7	7	6	5	5
800	9	8	8	8	8	7	7	7	6	5	5
900	9	8	8	8	8	7	7	7	6	5	5
1000	9	8	8	8	8	7	7	7	6	5	5
1100	9	8	8	8	8	7	7	7	6	5	5
1200	8	8	7	7	7	7	7	7	6	5	5
1300	8	8	7	7	7	7	7	6	6	5	5
1400	8	8	7	7	7	7	7	6	6	5	5
1500	8	8	7	7	7	7	7	6	5	5	5
1600	8	8	7	7	7	7	7	6	5	5	5
17	8	8	7	7	7	7	7	6	5	5	5

00											
1800	8	8	7	7	7	7	7	6	5	5	5
1900	7	7	7	7	7	7	6	6	5	5	5
2000	7	7	7	7	7	7	6	6	5	5	5
2100	7	7	6	6	6	6	6	6	5	5	5
2200	7	7	6	6	6	6	6	6	5	5	4
2300	7	7	6	6	6	6	6	6	5	5	4
2400	7	7	6	6	6	6	6	5	5	5	4
2500	6	6	6	6	6	6	6	5	5	4	4
2600	6	6	6	6	6	6	5	5	5	4	4
2700	6	6	6	6	6	5	5	5	5	4	4
2800	6	6	6	6	5	5	5	5	4	4	4
2900	6	6	5	5	5	5	5	5	4	4	4
3000	6	5	5	5	5	5	5	5	4	4	4
3500	5	5	5	5	5	4	4	4	4	4	3
4000	4	4	4	4	4	4	4	4	4	3	3
4500	4	4	4	4	4	4	4	3	3	3	3
5000	4	4	4	3	3	3	3	3	3	3	3
5500	3	3	3	3	3	3	3	3	3	3	3

Table 5F: Engines Greater Than 2,000 hp

Generic Modeling Results

Distance (ft)	8 ft height G_{hourly} (µg/m³)/(lb/hr)	10 ft height G_{hourly} (µg/m³)/(lb/hr)	12 ft height G_{hourly} (µg/m³)/(lb/hr)	14 ft height G_{hourly} (µg/m³)/(lb/hr)	16 ft height G_{hourly} (µg/m³)/(lb/hr)	18 ft height G_{hourly} (µg/m³)/(lb/hr)	20 ft height G_{hourly} (µg/m³)/(lb/hr)	25 ft height G_{hourly} (µg/m³)/(lb/hr)	30 ft height G_{hourly} (µg/m³)/(lb/hr)	35 ft height G_{hourly} (µg/m³)/(lb/hr)	40 ft height G_{hourly} (µg/m³)/(lb/hr)
50	7	6	6	6	5	5	5	5	4	4	4
100	7	6	6	6	5	5	5	5	4	4	4
150	7	6	6	6	5	5	5	5	4	4	4
200	7	6	6	6	5	5	5	5	4	4	4
300	7	6	6	6	5	5	5	5	4	4	4
400	7	6	6	6	5	5	5	5	4	4	4
500	7	6	6	6	5	5	5	5	4	4	4
600	7	6	6	6	5	5	5	5	4	4	4
700	7	6	6	6	5	5	5	5	4	4	4
800	6	6	6	6	5	5	5	5	4	4	4
900	6	6	6	6	5	5	5	5	4	4	4
1000	6	6	6	6	5	5	5	5	4	4	4
1100	6	6	6	6	5	5	5	5	4	4	4
1200	6	6	6	6	5	5	5	5	4	4	4
1300	6	6	6	6	5	5	5	5	4	4	4
1400	6	6	6	6	5	5	5	5	4	4	4
1500	6	6	6	6	5	5	5	5	4	4	4
1600	6	6	6	6	5	5	5	5	4	4	4
17	6	6	6	6	5	5	5	5	4	4	4

00											
1800	6	6	6	6	5	5	5	5	4	4	4
1900	6	6	6	5	5	5	5	5	4	4	4
2000	6	6	6	5	5	5	5	5	4	4	3
2100	5	5	5	5	5	5	5	5	4	4	3
2200	5	5	5	5	5	5	5	4	4	4	3
2300	5	5	5	5	5	5	4	4	4	4	3
2400	5	5	5	5	5	5	4	4	4	4	3
2500	5	5	5	5	4	4	4	4	4	4	3
2600	5	5	5	5	4	4	4	4	4	3	3
2700	5	5	5	5	4	4	4	4	4	3	3
2800	5	5	5	4	4	4	4	4	4	3	3
2900	4	4	4	4	4	4	4	4	4	3	3
3000	4	4	4	4	4	4	4	4	3	3	3
3500	4	4	4	4	4	4	3	3	3	3	3
4000	3	3	3	3	3	3	3	3	3	3	3
4500	3	3	3	3	3	3	3	3	3	2	2
5000	3	3	3	3	3	3	3	2	2	2	2
5500	3	3	3	3	3	2	2	2	2	2	2

~~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 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, Non-emergency, Spark-ignited	less than 500 hp	All dates	no standard	no standard	no standard
	greater than or equal to 500 hp	Before January 1, 2011	2	3	no standard
	greater than or equal to 500 hp	On or 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 500 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, Non-emergency, Spark-ignited	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
		On or after September 23, 1982, but prior to June 18, 1992 and rated 825 hp or greater	5	3	no standard
		On or 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, Non-emergency, Spark-ignited, and	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	Before September 23, 1982	5.0 except under reduced speed, 80-100% of full	3	no standard

Dual-fuel	500 hp		torque conditions may be 8.0		
		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
		On or after September 23, 1982, but prior to June 18, 1992 and rated 825 hp or greater	5	3	no standard
		On or 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 shall not emit greater than 25 ppmvd @15% NOx and 50 ppmvd @15% O2 for CO.				

~~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**
Exclusions	Control Systems	Control device monitoring and records are required only where the device is necessary for the site to meet emission rate limits
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. (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. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. Where appropriate, sampling ~~Sampling~~ shall occur as three one-hour test runs and then averaged to demonstrate compliance with the limits of this authorization ~~standard permit~~. Any deviations from those procedures must be approved in writing by the TCEQ Regional Director or his designee prior to sampling. (C) The Regional Office shall be afforded the opportunity to observe all such sampling. (D) The holder of this authorization is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. (E) The TCEQ Regional Office that has jurisdiction over the site shall be contacted as soon as any testing is scheduled, but not less than 30 days prior to sampling. The region shall have discretion to amend the 30 day prior notification. Except for engine testing and liquid/gas analysis sampling, all other sampling shall include an opportunity for the appropriate regional office to schedule a pretest meeting. The notice shall include: (i) Date for pretest meeting, if required; (ii)Date sampling will occur; (iii) Name of firm conducting sampling;

		(iv)Type of sampling equipment to be used; (v) Method or procedure to be used in sampling; (vi)Procedure used to determine operating rates or other relevant parameters during the sampling period; (vii) parameters to be documented during the sampling event; (viii) any proposed deviations to the prescribed sampling methods. If held, the purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. (F) Within 60 days after the completion of the testing and sampling required herein, one original and one copy of the sampling reports shall be sent to the Regional Office. (G) When sampling is required, all 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. 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), except 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 ~~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 site specific or a representative sample may be used to estimate emissions if all of the parameters in the gas and liquid analysis protocol provided by the commission are met.~~of the site.~~ An analysis shall be performed within 90 or 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. 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 / Glycol Contactor prior to dehydrator;(C) Amine Unit prior to sweetening unit; (D) Separator dumping to gunbarrel or storage tank; (E)Tanks for liquids and vapors; or (F) ~~and (E)~~ Produced Water or Brine/Salt Water at the inlet prior to storage. ~~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; (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 (O_2). 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 startup of each unit. Additional sampling shall occur as requested by the TCEQ Regional Director. 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. 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 unless records are unavailable and the permit holder performs the initial sampling on-site. No one may claim records are unavailable for the time period in which an engine is at the site which is authorized by this section. This testing is not required for emergency engines unless requested by the TCEQ Regional Director. Idle engines do not need to be re-started only for the purpose of completing required testing. If biennial testing is required for an engine that is re-started for production purposes, the biennial testing is required within 30 days after re-starting the engine.
Engines	Periodic Evaluation	The following is applicable to sites with federal operating permits only: (A) For any engine with a NO_X standard under Table 9 of this subsection, conduct evaluations of each engine performance semiannually after initial compliance testing by measuring the NO_X and CO content of the exhaust. Tests shall occur more than 90 days apart. Individual engines shall be subject to the semiannual performance evaluation if they were in operation for 2,000 hours or more during the six-month (semiannual) period. If an engine is not operating, the permit holder may delay the test until such time as the engine is expected to run for more than 14 days. Idled engines do not need to be re-started only for the purpose of completing required testing. (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 at minimum in accordance with the manufacturer's instructions. The operator may modify the procedure if it does not negatively alter the accuracy of the analyzer. Also, colorimetric testing (stain tubes) maybe used in these periodic evaluations. The NO_X and CO emissions

		then shall be converted into units of grams per horsepower-hour and pounds per hour. ~~(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.~~ ~~(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.~~ (C) Emissions shall be measured and recorded in the as-found operating condition, except no compliance determination shall be established during startup, shutdown, or under breakdown conditions. ~~After each occurrence of engine maintenance such as major component replacement, overhaul, oxygen sensor replacement, or catalyst replacement, an evaluation of engine performance as described above shall be performed within two weeks.~~ (D) In lieu of the above mentioned periodic monitoring for engines and biennial testing, the holder of this permit may install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to measure and record the concentrations of NO_X and CO from any engine, turbine, or other external combustion facility. Diluents to be 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.
Engines & Turbines	Biennial Testing Any engine greater than 500 horsepower or any turbine	Every two years starting from the completion date of the Initial Compliance Testing, any engine greater than 500 horsepower or any turbine shall be retested according to the procedures of the Initial Compliance Testing. Retesting shall occur within 90 days of the two-year anniversary date. 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 six calendar months (January to June or July to December). If biennial testing is required for an engine that is re-started for production purposes, the biennial testing shall be performed within 45 days after re-starting the engine.
~~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 when a company wants to establish efficiencies of 99% or greater, must be coordinated and approved. Sampling is required for VOC, benzene and H_2S at Region's discretion. The thermal oxidizer ~~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. 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 ±2.5°C. 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. 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.~~ ~~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.~~
Vapor Recovery Systems	Sampling to determine effectiveness	lVRU. The testing requires that a sample is analyzed using a PID and Method 21 or modified Method 21. Both the inlet and the outlet streams would need to be tested, and the difference would determine the efficiency. The equation is as follows: based on PID results, the mathematical equation to determine efficiency is *1-(inlet-outlet)/inlet*. This testing needs to be performed and results recorded to receive 95% control efficiency no longer than: vacuum truck emissions: after 20 loads have been pulled through the lVRU, for tanks: Produced Water – Monthly, Crude – Bi-Monthly, Condensate – Weekly. This testing needs to be performed and results recorded to receive 98% control efficiency no longer than: vacuum truck emissions: after 15 loads have been pulled through the lVRU, for tanks: Produced Water – 3 weeks, Crude – 10 days, Condensate – 5 days.

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	Accurate and detailed ~~As-built~~ plot plan with property line, off-site receptors, and all equipment on-site or drawings with sufficient detail to confirm all authorized facilities meet the requirements including, but not limited to, emission estimates, impact review, and registration scope.
Equipment specifications	Process units, tanks, vapor recovery systems ~~units~~; flares; thermal oxidizers; and reboiler control devices	A copy of the registration and emission calculations including the stationary equipment sizes and/or capacities and manufacturer's specifications and programs to maintain performance, with the plan and records for routine inspection, cleaning, repair and replacement. ~~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.~~
Physical Inspection	Fugitive Component Check	A record of the component count shall be maintained. A record of the date each quarterly inspection was made and the date that components were found leaking and when repaired or the date of the next planned shutdown.
Voluntary ~~Site~~ LDAR Program	Details of fugitive component monitoring plan, and LDAR results, including QA, QC	The following records are required where a company uses an LDAR program to reduce the potential fugitive emissions from the site to meet emission limitations or certify fugitive emissions. (A) A monitoring program plan must be maintained that contains, at a minimum, the following information: (i) an accounting of all the fugitive components by type and service at the site with the total uncontrolled fugitive potential to emit estimate; (ii) identification of the components at the site that are required to be monitored with an instrument or are exempt with the justification, note the following can be used for this purpose: (a) piping and instrumentation diagram (PID); or (b) a written or electronic database.; (iii) the monitoring schedule for each component at the site with difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), identified and justified, note if an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible

		during safe-to-monitor times and a record of the plan to monitor shall be maintained; and (iv) the monitoring method that will be used (audio, visual, or olfactory (AVO) means; Method 21; the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (v) for components where instrument monitoring is used, information clarifying the adequacy of the instrument response; (vi) the plan for hydraulic or pressure testing or instrument monitoring new and reworked components. (B) Records must be maintained of all monitoring instrument calibrations. (C) Records must be maintained for all monitoring and inspection data collected for each component required to be monitored with a Method 21 portable analyzer that include the type of component and the monitoring results in ppmv regardless if the screening value is above or below the leak definition.. (D) Leaking components must be tagged and a leaking-components monitoring log must be maintained for all leaks greater than the applicable leak definition (i.e.10,000 ppmv, 2000 ppmv, or 500 ppmv) of VOC detected using Method 21, all leaks detected by AVO inspection, and all leaks found using Alternative Work Practice specified in 40 CFR §60.18(g)-(i). The log must contain, at a minimum, the following: (i) the method used to monitor the leaking component (audio, visual, or olfactory inspection; Method 21; or the Alternative Work Practice in 40 CFR §60.18(g) - (i)); (ii) the name of the process unit or other appropriate identifier where the component is located; (iii) the type (e.g., valve or seal) and tag identification of component; (iv) the results of the monitoring (in ppmv if a Method 21 portable analyzer was used); (v) the date the leaking component was discovered;(vi) the date that a first attempt at repair was made to a leaking component; (vii) the date that a leaking component is repaired; (viii) the date and instrument reading of the recheck procedure after a leaking component is repaired; and (ix) the leaks that cannot be repaired until turnaround and the date that the leaking component is placed on the shutdown list. (E) If the owner or operator is using the Alternative Work Practice specified in 40 CFR §60.18(g) - (i), the records required by 40 CFR §60.18(i)(4). (F) A record of the monitored value any open-ended line or valve for which a repair or replacement is not completed within 72 hours and monitoring in lieu of covering is chosen. ~~Any open-ended line or valve which is a repair or replacement not completed within 72 hours shall be monitored on a weekly basis except that a leak is defined as any VOC reading greater than background. The results of~~

		~~this weekly check and any corrective actions taken shall be recorded.~~ (G) Audio, visual and olfactory inspections shall occur quarterly for BMP and at least weekly in concert with required instrument monitoring programs by operating personnel walk-through and be recorded. (H) A check of the reading for any pressure-sensing device to verify rupture disc integrity shall be performed weekly.
Minor Changes	Additions, changes or replacement of components or facilities	Records showing all replacements and additions, including summary of emission type and quantities for a rolling 60-month period.
Equipment Replacement	Like-Kind replacement	Records on equipment specifications and operations, including summary of emissions type and quantity.
Process Units	Glycol Dehydration Units	Glycol Dehydrator unit monitoring records include dry gas flow rate, absorber pressure and temperature, glycol type, and circulation rate recorded weekly. In addition to weekly unit monitoring where control of flash tank or reboiler emissions are required to meet the emission limitations of the section and emissions are certified, the following control monitoring requirements apply weekly: flash tank temperature and pressure, any reboiler stripping gas flow rate, and condenser outlet temperature. VRU, flare, or thermal oxidizer control or reboiler fire box used for control must comply with the monitoring and recordkeeping for those devices. Where all emissions from the flash tank and the reboiler or reboiler condenser vent are directed to a VRU, flare, or thermal oxidizer designed to be on-line at all times the glycol dehydrator is in operation, the control system monitoring for the glycol dehydrator is not required. ~~Records of Operational Monitoring and Testing Records (Glycol Solution, Contact Pressure, Temperature, and Pump Rate)~~
	Amine units ~~Process Separators~~	Amine units may simply retain site production or inlet gas records if all sulfur compounds in the inlet are assumed to be emitted. Records of the Amine Solution, Contactor Pressure, Temperature and Pump Rate shall be maintained where only partial removal of the inlet sulfur is assumed. Where the waste gas is vented to combustion control, the requirements of the control device utilized should be noted. ~~Records of Operational Monitoring and Testing Records (Worst Case Pressure)~~
	~~Oil/Water Separators used in pressurized system vs. ambient~~	~~Records of Operational Monitoring and Testing Records (Worst Case Pressure) For PBR no ambient requirements.~~

	~~conditions receiving a pressurized solution~~	
	~~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 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~~.~~, fuel flow meter, or other process variable that indicates a unit is running unless, in the registration for the facility, the emissions from the facility were calculated using full-year operation at maximum design capacity in which case no hours of operation records must be kept. ~~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. Records of the hours of operation of every combustion device and engine ~~engines~~ of any size by the use of a process monitor such as a run time meter run time meter, fuel flow meter, or other process variable that indicates a unit is running. The owner or operator may test and re-test choose to undergo testing and re-testing at the most frequent intervals identified in Table 7 in lieu of installing a process monitor and recording the hours of operation. If an engine has no testing requirements in Table 7 of this subsection, no records of the hours of operation must be kept. See fuel records below
Gas Fired Turbines	Combustion	Records of Appropriate Operational Monitoring and Testing Records Records of the hours of operation of every turbine greater than 500 hp ~~combustion device and engines of any size~~ by the use of a process monitor such as a run time meter, fuel flow meter, or other process variable that indicates a unit is running unless the permit holder determined emissions from the facility assuming full year operation at maximum design capacity in which case no hours of operation records must be kept. ~~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	A fuel flow meter is not required if emissions are based on maximum fuel usage for 8,760 hr/yr. There are no specific requirements for allowable VOC content of fuel. ~~For each separate fuel gas use at the site, the fuel usage and~~

		~~VOC content if the VOC content was used in emission estimation.~~ If field gas contains more than 1.5 grains (24 ppmv) of 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 design, inspection, and maintenance of paint color and vessel integrity.
Tanks/Vessels	Emission and emission potential	Maintain a record of the material stored in each tank/vessel that vents to the atmosphere and the maximum vapor pressure used to establish the maximum potential short-term emission rate. Where pressurized liquids can flash in the tank/vessel monitor and record weekly the maximum fluid pressure that can enter the tank/vessel. Records that tank/vessel hatches and relief valves are properly sealed when tank/vessel is directed to control and after loading events (as needed).
~~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 Commission. Cooling water VOC concentrations above 0.08 parts per million by volume (ppmv) indicate faulty equipment. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. Faulty equipment shall be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs. Records must be maintained of all monitoring data and equipment repairs.
	Particulate Monitoring, Maintenance and Repair.	Inspect and 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 month prior to any periodic blowdowns ~~week at manned sites or monthly at unmanned sites~~ and maintain records of the monitoring results and all corrective actions.
Planned Maintenance, Startup, and Shutdown (MSS) ~~Alternate Operations~~	Alternate Operational Scenarios and Redirection of Vent Streams ~~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 MSS	Pigging, Purging and Blowdowns	Pigging records, including catcher design, date, emission estimate to atmosphere and to control, and when controlled, the control device. Note: where a control device is necessary to meet emission limitations, the device is subject to the requirements of section (e) of this section and record requirements of this table. Purging and blowdown records, including the volume and pressure and a description of the piping and equipment involved, the date, emission estimate to atmosphere and to control, and when controlled, the control device. Where purging to control to meet a lower concentration before purging to atmosphere is conducted the concentrations of VOC, BTEX or H_2S, as appropriate, must be measured and recorded prior to purging to atmosphere. Note where a control device is necessary to meet emission limitations the device is subject to the requirements of section (e) of this section and record requirements of this table.
Planned MSS	Temporary Facilities for Bypass, and	Temporary facility records, including a description and estimate of potential fugitive emissions from temporary piping, size and design of facilities (eg. tanks or pan volume,

	Degassing and Purging	fill method, and throughput; engine horse power, fuel and usage time, flare tip area, ignition method, and heating value assurance method; etc.) and the date and emission estimate to atmosphere and to control for their use
Planned MSS	Management of Sludge from Pits, Ponds, Sumps and Water Conveyances	Records including the source and stream identification, removal plan, emission estimate that are direct to atmosphere and through a control. Note: where a control device is necessary to meet emission limitations, the device is subject to the requirements of section (e) of this section and record requirements of this table.
Planned MSS	Degassing or Purging of Tanks, Vessels, or Other Facilities	Records including: a) the EPN and description of vessels and equipment degassed or purged, with; b) the material, volume and pressure (if applicable); c) the volume of purge gas used; d) a description of the piping and equipment involved; e) clarifying estimates for a coated surface or heel; f) the date; g) emission estimate to atmosphere and to control; h) when controlled, the control device; and i) where purging to a control device to reduce concentrations before purging to atmosphere, the concentrations of VOC, BTEX or H_2S as appropriate must be measured and recorded prior to purging to atmosphere. j) the permit holder shall maintain a record of the estimated calculation demonstrating the benefit of a delay inrepair and provide upon request to a regulatory agency with jurisdiction.
~~Planned Maintenance, Startup, 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: • ~~Alternate operational scenarios or redirection of vent streams;~~ • ~~Pigging, purging, and blowdowns;~~

		~~• Temporary facilities meeting §106.263(e) of this title (relating to Routine Maintenance, Startup and Shutdown of Facilities and Temporary Maintenance Facilities) if used for degassing or purging of tanks, vessels, or other facilities;~~ ~~• Degassing or purging of tanks, vessels, or other facilities;~~ ~~• Management of sludge from pits, ponds, sumps, and water conveyances;~~ ~~• Amine and other treatment chemicals replacement (except glycols);~~ ~~• Hot oil treatments.~~ • Routine engine component maintenance including filter changes, oxygen sensor replacements, compression checks, overhauls, lubricant changes, spark plug changes, and emission control system maintenance; • Boiler refractory replacements and cleanings; • Heater and heat exchanger cleanings; ~~• Cleaning of separator, amine, and dehydrator dump valves;~~ ~~• Amine filter replacements;~~ • Turbine hot section swaps; • Pressure relief valve testing, calibration of analytical equipment; instrumentation/analyzer maintenance; replacement of analyzer filters and screens.
Control Devices	Flare Monitoring	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. 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. Basic monitoring is a thermocouple or infrared monitor that indicates the device is working. Records of hours of use are required for all units and on-line time must be considered when emission estimates and actual emissions inventories are calculated.
	Intermediate	Intermediate monitoring and records include continuously monitoring and recording temperature to insure the control device is working when waste gas can be directed to the device and showing compliance with the 1400 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.~~ ~~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	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. mVRU Basic Design Function Record: Record demonstrating the unit captures vapor and includes a sensing device set to capture this vapor at peak intervals. Additional Design Parameter Record: Record demonstrating additional design parameters are utilized such as additional sensing equipment, a properly designed bypass system, an appropriate gas blanket, an adequate compressor selection, and the ability to vary the drive speed for units utilizing electric driven compressors mVRUs that are used at oil and gas sites to control emissions may claim up to 100% control efficiency provided records of basic and additional design functions and parameters of a VRU along with appropriate records listed in Table 8 are satisfied. mVRUs may claim up to 99% control efficiency for units where records of basic and additional design function and parameters listed in Table 8 are satisfied. mVRUs may claim up to 95% control efficiency for units where records listed in Table 8 are not satisfied. lVRU

		The record of proper design must be kept to demonstrate how the unit was designed and for what capacity. The record of liquid replacement must be kept, along with the calculations for demonstrating that the VOC to liquid ratio has been maintained. Additionally, the system must be tested to demonstrate the efficiency. This testing needs to be performed and results recorded to receive 95% control efficiency no longer than: vacuum truck emissions: after 20 loads have been pulled through the lVRU, for tanks: Produced Water – Monthly, Crude – Bi-Monthly, Condensate – Weekly. This testing needs to be performed and results recorded to receive 98% control efficiency no longer than: vacuum truck emissions: after 15 loads have been pulled through the lVRU, for tanks: Produced Water – 3 weeks, Crude – 10 days, Condensate – 5 days. All valves must be designed and maintained to prevent leaks. All hatches and openings must be properly gasketed and sealed with the unit properly connected. Downtime is limited to a rolling 12 month average of 5% or 432 hr/per rolling 12 months and waste vents shall be redirected to an appropriate control device if possible during down time. ~~Monitoring and records are required only where the vapor recovery 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.~~ ~~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.~~ Basic monitoring is any continuous monitor that indicates when the flame in the device is on or off (other than partial operational use). The following are effective basic options ~~and can include or~~ : a fire box temperature monitor, rising or steady process temperature monitor, CO monitor, primary fuel flow monitor, fire box pressure monitor or equivalent.

		Enhanced monitoring for 91 to 99% control, where waste gas is not introduced as the primary fuel, ~~is required for greater control and partial operational claims. These~~ must include the following monitors: continuous fire box or fire box exhaust temperature, and 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 where more than 50% run time of control is claimed.
~~Monitoring~~	~~As Applicable~~	~~When monitoring is required, all QA/QC shall follow 30 TAC Ch 25 NELAC accreditation requirements.~~

Table 9 Fugitive Component Leak Detection and Repair (LDAR) Control Program Table

General: All fugitive components at an OGS registered with this rule need to be evaluated for potential emissions with the Oil and Gas factors for impact analysis. The requirements of this table and requirements regarding fugitive component monitoring in Tables 7 and 8 of this subsection must be met to apply LDAR control program reductions in this table. Compliance with these requirements does not assure compliance with requirements of NSPS, NESHAPS or MACT or State Regulations, and does not constitute approval of alternate standards for those regulations.	**Note:** where the estimated emissions from an OGS registered with this rule can meet emission limitations of the rule without reductions of an LDAR control program, then any LDAR control program may be implemented without being subject to these requirements.
Exceptions *If implemented by the permit holder and relied upon for emission reductions, fugitive components must meet the minimum design, monitoring, control, and other emissions techniques listed in this Table unless the component's service meets one of the following exceptions:*	**Additional Details**
Nitrogen lines	No expectation to estimate emissions. Note this exemption does not include lines with nitrogen that has been used as a sweep gas.
Steam lines (non contact)	No expectation to estimate emissions.
Flexible plastic tubing ≤ 0.5 inches in diameter, unless it is subject to monitoring by other state or federal regulations.	No expectation to estimate emissions, unless it is subject to monitoring by other state or federal regulations.
The operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure	No expectation to estimate emissions.
Mixtures in streams where the VOC has an aggregate partial pressure of less than 0.002 psia at 68°F.	No expectation to estimate emissions.
Components containing only noble gases, inerts such as CO_2 and water or air contaminants not typically listed on a MAERT such as methane, ethane, and Freon.	No expectation to estimate emissions.
Instrument monitoring is not required for pipeline quality sweet natural gas	Uncontrolled Emissions should be estimated. Must meet pipeline quality specifications
Instrument monitoring is not required when the aggregate partial pressure or vapor	Uncontrolled Emissions should be estimated. This applies at all times, unless

pressure is less than 0.044 psia at 68 ºF or at maximum process operating temperature.	a control efficiency is being claimed for instrument monitoring, in which case there must be a record supporting that the instrument could detect a leak.
Instrument monitoring is not required for waste water lines containing less than 1% VOC by weight and operated at ≤ 1 psig	Uncontrolled Emissions should be estimated.
Instrument monitoring is not required for cooling water line components	Emissions are estimated and associated with the cooling tower
Instrument monitoring is not required for CO_2 lines after VOC is removed. This is referred to as Dry Gas lines in 40 CFR Part 60 Subpart KKK, and defined as a stream having a VOC weight percentage less than 4 %; a weighted average Effects Screening Level (ESL) of the combined VOC stream is > 3,500 μg/m^3; and total uncontrolled emissions for all such sources is < 1 ton per year at any OGS.	Uncontrolled Emissions should be estimated as follows: The weighted average ESL_x for process stream, X, with multiple VOC species will be determined by: $ESL_x = fa/ESL_a + f_b/ESL_b + f_c/ESL_c + ... + fn/ESL_n$ Where: n =total number of VOC species in process stream; ESL_n = the effects screening level in µg/m^3 for the contaminant being evaluated (published in the most recent edition of the TCEQ ESL list); f_n=the weight fraction of the appropriate VOC species in relation to all other VOC in process stream.
Requirements	**Additional Details and Reduction Credit**
Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.	
New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.	
New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter.	
Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the	

components being returned to service. Where technically feasible new and reworked components may be screened for leaks with a soap bubble test within 8 hours of being returned to service in lieu of instrument testing. Adjustments shall be made as necessary to obtain leak-free performance.	
Components shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.	The weekly physical inspection applies a 30 % reduction credit to all fugitive components not subject to an instrument monitoring check.
Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line so that no leakage occurs. Except during sampling, both valves shall be closed. If the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period; i. a cap, blind flange, plug, or second valve must be installed on the line or valve; or ii. the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once at the end of the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings 20 ppmv above background and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.	Application of this requirement eliminates the expectation to estimate emissions from open ended lines and valves.
Accessible valve shall be monitored by leak-checking for fugitive emissions quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not	Sealless/leakless valves and relief valves equipped with rupture disc or venting to a control device and exempted from instrument monitoring are not counted in

limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If an unsafe-to-monitor valve is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually. For relief valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity and checked weekly. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.	the fugitive emissions estimates. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements. See Table 8, Monitoring and Records Demonstrations to identify Difficult-to-monitor and unsafe-to-monitor valves.
All pump, compressor and agitator seals shall be monitored quarterly with an approved gas analyzer or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be instrument monitored. Seal systems that prevent emissions may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure or seals degassing to vent control systems kept in good working order. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.	Pumps compressor and agitator seals that prevent leaks or direct emissions from the seals to control and are exempt from instrument monitoring are not counted in the fugitive emissions estimates. Equipment equipped with alarms would still be counted. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.
Components found to be emitting VOC in excess of a 10,000 parts per million by volume (ppmv) leak definiton using EPA Method 21, found by visual inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) or found leaking using the Alternative Work Practice in 40 CFR	Components subject to routine instrument monitoring with an approved gas analyzer or the alternative work practice under this leak definition my claim a 75% emission reduction credit when evaluating controlled fugitive emission estimates. This reduction credit does not apply when evaluating uncontrolled emission or to any

§60.18(g) - (i) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified.	component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements
Components **not** subject to a instrument monitoring program but found to be emitting VOC in excess of 10,000 ppmv leak definiton using EPA Method 21, found by audio, visual or olfactory inspection to be leaking (e.g. whistling, dripping or blowing process fluids or emitting hydrocarbon or H_2S odors) shall be considered to be leaking and shall be repaired, replaced, or tagged as specified. All components are subject to monitoring when using the Alternative Work Practice in 40 CFR §60.18(g) - (i).	
Components shall be repaired in accordance with subsection (e)(6)(D) of this section.	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 site has a planned shutdown schedule and 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.
Instrument monitoring and the reduction credit associated may not be applied to components where the gas saturation concentration of the fluid contained would be below the leak definition.	Where components fluids contain sufficient methane and ethane to allow detection by the instrument monitoring the components can be monitored and take the emission reduction credit.
Enhanced LDAR Monitoring Options	Any site may reduce the controlled fugitive emission estimates by including components not required to be monitored in the quarterly instrument monitoring program or applying the lower leak definition of the more stringent program as appropriate.
Component groups (eg. flanges and connectors) may implement quarterly instrument monitoring using EPA Method	Quarterly monitoring at a leak definition of 10,000 ppmv would equate to a 75% emission reduction credit when evaluating

21 with a leak definition of 10,000 ppmv.	controlled fugitive emission estimates for the instrument monitored component group.
A lower leak definition of 2000 ppmv may be applied to pump, compressor, and agitator seals when instrument monitoring using EPA Method 21 quarterly.	OGS using this lower leak definition for pump, compressor, and agitator seals may apply an 85% emission reduction credit for quarterly monitoring of those components. This reduction credit does not apply when evaluating uncontrolled emissions or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.
A lower leak definition of 500 ppmv may be applied to any fugitive component group when instrument monitoring using EPA Method 21 quarterly.	OGS using this lower leak definition for valves, flanges or connectors may apply a 97% emission reduction credit; pumps may apply a 93% emission reduction credit; and compressor, agitator seals and other component groups may apply a 95% emission reduction credit for quarterly monitoring of those components. This reduction credit does not apply when evaluating uncontrolled emission or to any component not measured with an instrument quarterly. See Table 7 Sampling and Demonstrations of Compliance for Fugitive and LDAR Analyzer requirements.
Instrument Monitoring Frequency Adjustments	
After completion of the required quarterly inspections for a period of at least two years, the operator of the OGS facility may change the monitoring schedule as follows: (i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service; (ii) After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service. If the owner or operator is using the	At the discretion of the TCEQ Commission or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

Alternative Work Practice in 40 CFR §60.18(g) - (i), the alternative frequencies specified in this standard permit are not allowed.	

~~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~~	~~Before September 23, 1982~~	~~5.0 except under reduced speed, 80-100% of full torque~~	~~3~~	~~no standard~~

	~~500 hp~~		~~conditions may be 8.0~~		
		~~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.~~				