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APR 27 2010
EXECUTIVE DIRECTOR

April 14, 2010

Texas Commission on Environmental Quality
Attn: Mr. Mark R. Vickery, P.G., Executive Director
P.O. Box 13087
Austin, TX 78711-3087

RE: PETITION FOR ADOPTION OF A MODIFICATION TO TCEQ RULE REGULATING MINOR COMBUSTION SOURCES IN DALLAS

Dear Mr. Vickery:

Ameresco Dallas LLC (Ameresco) owns and will operate the Ameresco Biogas Energy (the Facility), located at 10011 Log Cabin Rd, Dallas, Texas. The Facility will combust digester bio-gas from the Dallas Southside Wastewater Treatment Plant (SWWTP) in lean burn internal combustion engines to produce electricity and thermal energy. The Facility is currently authorized to be constructed and operated under a Texas Commission on Environmental Quality (TCEQ) standard permit for electric generating units (Permit No. 87504), and it has been designed to achieve the permit's nitrogen oxide (NOx) emission limit for digester fuel. We are petitioning to modify the special Dallas rule discussed below because we believe it inadvertently sets more stringent NOx requirements.

PETITION FOR ADOPTING A RULE MODIFICATION

Ameresco Dallas LLC (regulated entity RN105690853) is submitting a petition for rulemaking pursuant to Texas Administrative Code (TAC) Title 30 Part 1 Chapter 20, Rule 20.15. Ameresco petitions TCEQ to modify **TAC Title 30, Part 1, Chapter 20, Rule 117.2110 (a)(1)(B)(ii)(I)** to include digester bio-gas under the same emission standard as landfill gas.

The subsection of the rule to be modified currently reads:

> ***(I) fired on landfill gas, 0.60 g/hp-hr: ...***

Under Texas code Section 2001.021, Ameresco is an interested party requesting that a revision to **Rule 117.2110 (a)(1)(B)(ii)(I)** be adopted, with the modification to read:

> ***(I) fired on landfill gas <u>or digester gas</u>, 0.60 g/hp-hr:***
>
> ***or alternatively "fired on landfill <u>or other biogas</u>, 0.6 g/hp-hr "***

DISCUSSION

Digester gas and landfill gas are two similar renewable fuels, and the emission requirements for combusting these biogases should be the same. The current rule (see Attachment A for full text) establishes emission standards for internal combustion (IC) engines located at minor sources of NOx in the Dallas-Ft Worth Ozone Non-attainment Area. Specifically, the rule as it applies to this Facility requires lean burn, reciprocating IC engines to comply with an emission standard of 0.6 g/bhp-hr when combusting landfill gas, and 0.5 g/bhp-hr when combusting other gaseous fuel(s). Landfill gas is the only non-conventional, renewable bio-gas fuel granted a 20% higher emission limit. Thus, an engine generator of any size that combusts digester gas must comply with the 0.5 g/bhp-hr standard. Some engines burning other fuels under the same rule are allowed NOx emissions of 4.5 g/bhp-hr or more.

The following precedents for considering these biogases under the same regulatory scheme are discussed below:

- TCEQ Standard Permit for Electric Generating Units
- Similar Fuel and Combustion Characteristics
- Federal New Source Performance Standard Subpart JJJJ

TCEQ Standard Permit for Electric Generating Units

The standard permit for electric generating units states that "Electric generating units firing any gaseous or liquid fuel that is at least 75 percent landfill gas, digester gas, stranded oil field gas, or renewable fuel by volume shall meet a NOx emission limit of 1.90 lb/MWh" (see Attachment B).

The NOx emission limit in the standard permit for electric generating units is more lenient for both landfill and digester gas than for natural gas. This suggests that TCEQ considered landfill gas and digester gas to be special, non-commercial fuels that could meet the same NOx emission limit, and it was an acceptable tradeoff to use these otherwise wasted fuels despite their slightly higher emissions. The standard permit applies the same emission requirement to these two fuels, and we believe the Dallas County rule should also address digester gas in the same way as landfill gas.

Similar Fuel and Combustion Characteristics

Landfill gas and digester gas are produced from the same biological process, anaerobic digestion (or decomposition) of organic matter. An article on Biogas Technology[1] explains "The same anaerobic digestion process that produces biogas from animal manure and wastewater occurs naturally underground in landfills". (Attachment C). Both gases have similar characteristics, and their combustion design and emissions are similar.

Any number of organic wastes from agriculture, food service or industrial processes can be anaerobically decomposed and will produce gas with a methane content in the range of 45-70%, creating a medium heat content fuel. However, due to individual organic feedstocks and decomposition conditions, biogas quality and trace contaminant levels often vary to some degree over time and from facility to facility.

[1] http://www.oregon.gov/ENERGY/RENEW/Biomass/biogas.shtml

In a landfill, bacteria feed on the buried trash to decompose it, and when the available oxygen is used up, anaerobic bacteria, those that do not need oxygen, take over to continue decomposition. At a wastewater treatment plant, vessels can be designed as a suitable environment for anaerobic bacteria to digest (decompose) waste activated sludge. As in a landfill, the anaerobic bacteria driving this dewatering and volume reduction process will produce an off-gas with significant methane content.

The combustion and emission characteristics of lean-burn, reciprocating engines using medium heat content biogases are similar. Gaseous fuels generate NOx emissions based on the fuel nitrogen content, combustion temperature and pressure, and the fuel/air mixture in the combustion equipment. Fuel and combustion design factors that contribute to NOx emissions have been described in USEPA's Compilation of Emission Factors for internal combustion sources (AP-42 Section 3[2], Attachment D).

Federal New Source Performance Standard 40 CFR 60 Subpart JJJJ

The federal new source performance standard (NSPS) 40 CFR Part 60 Subpart JJJJ (see Attachment E) established emission standards for NOx, CO, and VOC for spark ignition reciprocating internal combustion engines based on combustion and add-on control system capability. Lean-burn engines firing digester gas are allowed the same emission rate that applies to similar engines combusting landfill gas, and the rate is higher than the standard for natural gas, 3.0 g NOx/hp-hr rather than 2.0 g/hp-hr. Tables 1 and 4 of Subpart JJJJ categorize digester gas and landfill gas together and require them to meet the same emission standard.

Subpart JJJJ does not classify digester gas and landfill gas in different categories; the two biofuels should have the same NOx emission requirement.

For the above reasons, Ameresco Dallas LLC requests that you modify the above noted rule to modify the NOx emission limit for digester gas to be the same, slightly higher value as landfill gas. Failure to adopt this rule change will result in unequal emission standards for use of two renewable fuels with similar and relatively low emissions. Please contact me at 508-661-2231 if you have questions.

By: Ameresco Dallas LLC

By: Ameresco, Inc., its sole member,

Joseph P. De Manche, executive vice president

Cc: R. Bell, S. Simon, C. VonSaltza, Ameresco
B. Labno, R. Birkenholz, Golder

[2] http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf

ATTACHMENT A:

TCEQ RULE FOR MINOR COMBUSTION SOURCES IN DALLAS

SUBCHAPTER D: COMBUSTION CONTROL AT MINOR SOURCES IN OZONE NONATTAINMENT AREAS
DIVISION 2: DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA MINOR SOURCES
§§117.2100, 117.2103, 117.2110, 117.2125, 117.2130, 117.2135, 117.2145
Effective June 14, 2007

§117.2100. Applicability.

This division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources) applies in the Dallas-Fort Worth eight-hour ozone nonattainment area to stationary, reciprocating internal combustion engines at any stationary source of nitrogen oxides (NO_X) that is not a major source of NO_X.

Adopted May 23, 2007 Effective June 14, 2007

§117.2103. Exemptions.

This division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources) does not apply to the following stationary engines, except as specified in §§117.2130(c), 117.2135(e), and 117.2145(b) and (c) of this title (relating to Operating Requirements; Monitoring, Notification, and Testing Requirements; and Recordkeeping and Reporting Requirements):

(1) engines with a horsepower (hp) rating of less than 50 hp;

(2) engines used in research and testing;

(3) engines used for purposes of performance verification and testing;

(4) engines used solely to power other engines or gas turbines during startups;

(5) engines operated exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 100 hours per year, based on a rolling 12-month average. Any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after June 1, 2007, is ineligible for this exemption. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations (CFR) §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account;

(6) engines used in response to and during the existence of any officially declared disaster or state of emergency;

(7) engines used directly and exclusively by the owner or operator for agricultural operations necessary for the growing of crops or raising of fowl or animals;

(8) diesel engines placed into service before June 1, 2007, that:

(A) operate less than 100 hours per year, based on a rolling 12-month average; and

(B) have not been modified, reconstructed, or relocated on or after June 1, 2007. For the purposes of this clause, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account; and

(9) new, modified, reconstructed, or relocated stationary diesel engines placed into service on or after June 1, 2007, that:

(A) operate less than 100 hours per year, based on a rolling 12-month average, in other than emergency situations; and

(B) meet the corresponding emission standard for non-road engines listed in 40 CFR §89.112(a), Table 1 (October 23, 1998) and in effect at the time of installation, modification, reconstruction, or relocation. For the purposes of this subparagraph, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title and 40 CFR §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title, a used engine from anywhere outside that account.

Adopted May 23, 2007 Effective June 14, 2007

§117.2110. Emission Specifications for Eight-Hour Attainment Demonstration.

(a) The owner or operator of any source subject to this division (relating to Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources) shall not allow the discharge into the atmosphere emissions of nitrogen oxides (NO_X) in excess of the following emission specifications.

(1) Emission specifications for stationary, gas-fired, reciprocating internal combustion engines are as follows:

(A) rich-burn engines:

(i) fired on landfill gas, 0.60 grams per horsepower-hour (g/hp-hr); and

(ii) all other rich-burn engines, 0.50 g/hp-hr; and

(B) lean-burn engines:

(i) placed into service before June 1, 2007, that have not been modified, reconstructed, or relocated on or after June 1, 2007, 0.70 g/hp-hr; and

(ii) placed into service, modified, reconstructed, or relocated on or after June 1, 2007:

(I) fired on landfill gas, 0.60 g/hp-hr; and

(II) all other lean-burn engines, 0.50 g/hp-hr.

(2) The emission specification for stationary, dual-fuel, reciprocating internal combustion engines is 5.83 g/hp-hr.

(3) Emission specifications for stationary, diesel, reciprocating internal combustion engines are as follows:

(A) placed into service before March 1, 2009, that have not been modified, reconstructed, or relocated on or after March 1, 2009, the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data; and

(B) for engines not subject to subparagraph (A) of this paragraph:

(i) with a horsepower (hp) rating of 50 hp or greater, but less than 100 hp, that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 3.3 g/hp-hr;

(ii) with a horsepower rating of 100 hp or greater, but less than or equal to 750 hp, that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 2.8 g/hp-hr; and

(iii) with a horsepower rating of 750 hp or greater that are installed, modified, reconstructed, or relocated on or after March 1, 2009, 4.5 g/hp-hr.

(4) As an alternative to the emission specifications in paragraphs (1) – (3) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu heat input. For units placed into service on or before December 31, 2000, the annual capacity factor as of December 31, 2000, must be used to determine eligibility for the alternative emission specification of this paragraph. For units placed into service after December 31, 2000, a 12-month rolling average must be used to determine the annual capacity factor.

(5) For the purposes of this subsection, the terms "modification" and "reconstruction" have the meanings defined in §116.10 of this title (relating to General Definitions) and 40 Code of Federal Regulations §60.15 (December 16, 1975), respectively, and the term "relocated" means to newly install at an account, as defined in §101.1 of this title (relating to Definitions), a used engine from anywhere outside that account.

(b) The averaging time for the NO_X emission specifications of subsection (a) of this section is as follows:

(1) if the unit is operated with a NO_X continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.2135(c) of this title (relating to Monitoring, Notification, and Testing Requirements), either as:

ATTACHMENT B:

STANDARD PERMIT FOR ELECTRIC GENERATING UNITS

Air Quality Standard Permit for Electric Generating Units
Effective Date May 16, 2007

This standard permit authorizes electric generating units that generate electricity for use by the owner or operator and/or generate electricity to be sold to the electric grid, and that meet all of the conditions listed below.

(1) Applicability

(A) This standard permit may be used to authorize electric generating units installed or modified after the effective date of this standard permit and that meet the requirements of this standard permit.

(B) This standard permit may not be used to authorize boilers. Boilers may be authorized under the Air Quality Standard Permit for Boilers; 30 TAC § 106.183, Boilers, Heaters, and Other Combustion Devices; or a permit issued under the requirements of 30 TAC Chapter 116.

(2) Definitions

(A) East Texas Region - All counties traversed by or east of Interstate Highway 35 or Interstate Highway 37, including Bosque, Coryell, Hood, Parker, Somervell and Wise Counties.

(B) Installed - a generating unit is installed on the site when it begins generating electricity.

(C) West Texas Region - Includes all of the state not contained in the East Texas Region.

(D) Renewable fuel - fuel produced or derived from animal or plant products, byproducts or wastes, or other renewable biomass sources, excluding fossil fuels. Renewable fuels may include, but are not limited to, ethanol, biodiesel, and biogas fuels.

(3) Administrative Requirements

(A) Electric generating units shall be registered in accordance with 30 TAC § 116.611, Registration to Use a Standard Permit, using a current Form PI-1S. Units that meet the conditions of this standard permit do not have to meet 30 TAC § 116.610(a)(1), Applicability.

(B) Registration applications shall comply with 30 TAC § 116.614, Standard Permit Fees, for any single unit or multiple units at a site with a total generating capacity of 1 megawatt (MW) or greater. The fee for units or multiple units with a total generating capacity of less than 1 MW at a site shall be $100.00. The fee shall be waived for units or multiple units with a total generating capacity of less than 1 MW at a site that have certified nitrogen oxides (NO_x) emissions that are less than 10 percent of the standards required by this standard permit.

(C) No owner or operator of an electric generating unit shall begin construction and/or operation without first obtaining written approval from the executive director.

(D) Records shall be maintained and provided upon request to the Texas Commission on Environmental Quality (TCEQ) for the following:

(i) Hours of operation of the unit;

(ii) Maintenance records, maintenance schedules, and/or testing reports for the unit to document re-certification of emission rates as required by subsection (4)(G) below; and

(iii) Records to document compliance with the fuel sulfur limits in subsection (4)(C).

(E) Electric generators powered by gas turbines must meet the applicable conditions, including testing and performance standards, of Title 40 Code of Federal Regulations (CFR) Part 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, and applicable requirements of 40 CFR Part 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

(F) Compliance with this standard permit does not exempt the owner or operator from complying with any applicable requirements of 30 TAC Chapter 117, Control of Air Pollution from Nitrogen Compounds, or 30 TAC Chapter 114, Control of Air Pollution from Motor Vehicles.

(4) General Requirements

(A) Emissions of NO_x from the electric generating unit shall be certified by the manufacturer or by the owner or operator in pounds of pollutant per megawatt hour (lb/MWh). This certification must be displayed on the name plate of the unit or on a label attached to the unit. Test results from U.S. Environmental Protection Agency (EPA) reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director used to verify this certification shall be provided upon request to the TCEQ. The unit must operate on the same fuel(s) for which the unit was certified.

(B) Electric generating units that use combined heat and power (CHP) may take credit for the heat recovered from the exhaust of the combustion unit to meet the emission standards in subsections (4)(D), (4)(E), and (4)(F). Credit shall be at the rate of one MWh for each 3.4 million British Thermal Units of heat recovered. The following requirements must be met to take credit for CHP for units not sold and certified as an integrated package by the manufacturer:

(i) The owner or operator must provide as part of the application documentation of the heat recovered, electric output, efficiency of the generator alone, efficiency of the generator including CHP, and the use for the non-electric output, and

(ii) The heat recovered must equal at least 20 percent of the total energy output of the CHP unit.

(C) Fuels combusted in these electric generating units are limited to:

(i) Natural gas containing no more than ten grains total sulfur per 100 dry standard cubic feet;

(ii) Landfill gas, digester gas, stranded oilfield gas, or gaseous renewable fuel containing no more than 30 grains total sulfur per 100 dry standard cubic feet; or

(iii) Liquid fuels (including liquid renewable fuel) not containing waste oils or solvents and containing less than 0.05 percent by weight sulfur.

(D) Except as provided in subsections (4)(F) and (4)(H), NO_x emissions for units 10 MW or less shall meet the following limitations based upon the date the unit is installed and the region in which it operates:

East Texas Region:

(i) Units installed prior to January 1, 2005 and

(a) operating more than 300 hours per year - 0.47 lb/MWh;

(b) operating 300 hours or less per year - 1.65 lb/MWh;

(ii) Units installed on or after January 1, 2005 and

(a) operating more than 300 hours per year, with a capacity greater than 250 kilowatts (kW) - 0.14 lb/MWh;

(b) operating 300 hours or less per year - 0.47 lb/MWh; or

(c) any unit with a capacity of 250 kW or less - 0.47 lb/MWh.

West Texas Region:

(i) Units operating more than 300 hours per year - 3.11 lb/MWh;

(ii) Units operating 300 hours or less per year - 21 lb/MWh. Units certified to comply with applicable Tier 1, 2, or 3 emission standards in 40 CFR Part 89, Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines, are deemed to satisfy this emission limit.

(E) Except as provided in subsections (4)(F) and (4)(H), NO_x emissions for units greater than 10 MW shall meet the following limitations:

(i) Units operating more than 300 hours per year - 0.14 lb/MWh;

(ii) Units operating 300 hours or less per year - 0.38 lb/MWh.

(F) Electric generating units firing any gaseous or liquid fuel that is at least 75 percent landfill gas, digester gas, stranded oil field gas, or renewable fuel content by volume, shall meet a NO_x emission limit of 1.90 lb/MWh. Units in West Texas with a capacity of 10 MW or less that fire at least 75 percent landfill gas, digester gas, stranded oilfield gases, or gaseous or liquid renewable fuel by volume, must comply with the applicable West Texas NO_x limit in subsection (4)(D).

(G) To ensure continuing compliance with the emissions limitations, the owner or operator shall re-certify a unit every 16,000 hours of operation, but no less frequently than every three years. Re-certification may be accomplished by following a maintenance schedule that the manufacturer certifies will ensure continued compliance with the required NO_x standard or by third party testing of the unit using appropriate EPA reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director to demonstrate that the unit still meets the required emission standards. After re-certification, the unit must operate on the same fuel(s) for which the unit was re-certified.

(H) The NO_x emission limits in subsections (4)(D)-(4)(F) are subject to the following exceptions:

(i) The hourly NO_x emission limits do not apply at times when the ambient air temperature at the location of the unit is less than 0 degrees Fahrenheit.

(ii) At times when a unit is operating at less than 80% of rated load, an alternative NO_x emission standard for that unit may be determined by multiplying the applicable emission standard in subsections (4)(D)-(4)(F) by the rated load of the EGU (in MW), to produce an allowable hourly mass NO_x emission rate. In order to use this alternative standard, an owner or operator must maintain records that demonstrate compliance with the alternative emission standard, and make such records available to the TCEQ or any local air pollution control agency with jurisdiction upon request.

ATTACHMENT C:

BioGas Technology Article

Biogas Technology

Anaerobic Digestion

In recent years, increasing awareness that anaerobic digesters can help control the disposal and odor of animal waste has stimulated renewed interest in the technology. Dairy farmers faced with increasing federal and state regulation of the waste their animals produce are looking for ways to comply. New digesters now are being built because they effectively eliminate the environmental hazards of dairy farms and other animal feedlots.

It is often the environmental reasons - rather than the digester's electrical and thermal energy generation potential - that motivate farmers to use digester technology. This is especially true in areas where electric power costs are low.

Anaerobic digester systems can reduce fecal coliform bacteria in manure by more than 99 percent, virtually eliminating a major source of water pollution. Separation of the solids during the digester process removes about 25 percent of the nutrients from manure, and the solids can be sold out of the drainage basin where nutrient loading may be a problem.

In addition, the digester's ability to produce and capture methane from the manure reduces the amount of methane that otherwise would enter the atmosphere. Scientists have targeted methane gas in the atmosphere as a contributor to global climate change.

Digester Technology

Biomass that is high in moisture content, such as animal manure and food-processing wastes, is suitable for producing biogas using anaerobic digester technology.

Anaerobic digestion is a biochemical process in which particular kinds of bacteria digest biomass in an oxygen-free environment. Several different types of bacteria work together to break down complex organic wastes in stages, resulting in the production of "biogas."

Symbiotic groups of bacteria perform different functions at different stages of the digestion process. There are four basic types of microorganisms involved. Hydrolytic bacteria break down complex organic wastes into sugars and amino acids. Fermentative bacteria then convert those products into organic acids. Acidogenic microorganisms convert the acids into hydrogen, carbon dioxide and acetate. Finally, the methanogenic bacteria produce biogas from acetic acid, hydrogen and carbon dioxide.

Controlled anaerobic digestion requires an airtight chamber, called a digester. To promote bacterial activity, the digester must maintain a temperature of at least 68° F. Using higher temperatures, up to 150° F, shortens processing time and reduces the required volume of the tank by 25 percent to 40 percent. However, there are more species of anaerobic bacteria that thrive in the temperature range of a standard design (mesophillic bacteria) than there are species that thrive at higher temperatures (thermophillic bacteria). High-temperature digesters also are more prone to upset because of temperature fluctuations and their successful operation requires close monitoring and diligent maintenance.

The biogas produced in a digester (also known as "digester gas") is actually a mixture of gases, with methane and carbon dioxide making up more than 90 percent of the total. Biogas typically contains smaller amounts of hydrogen sulfide, nitrogen, hydrogen, methylmercaptans and oxygen.

Methane is a combustible gas. The energy content of digester gas depends on the amount of methane it contains. Methane content varies from about 55 percent to 80 percent. Typical digester gas, with a methane concentration of 65 percent, contains about 600 Btu of energy per cubic foot.

For individual farms, small-scale plug-flow or covered lagoon digesters of simple design can produce biogas for on-site electricity and heat generation. For example, a plug-flow digester could process 8,000 gallons of manure per day, the amount produced by a herd of 500 dairy cows. By using digester gas to fuel an engine-generator, a digester of this size would produce more electricity and hot water than the dairy consumes.

Larger scale digesters are suitable for manure volumes of 25,000 to 100,000 gallons per day. In Denmark and in several other European countries, central digester facilities use manure and other organic wastes collected from individual farms and transported to the facility.

Types of Anaerobic Digesters

There are three basic digester designs. All of them can trap methane and reduce fecal coliform bacteria, but they differ in cost, climate suitability and the concentration of manure solids they can digest.

A **covered lagoon digester**, as the name suggests, consists of a manure storage lagoon with a cover. The cover traps gas produced during decomposition of the manure. This type of digester is the least expensive of the three.

Covering a manure storage lagoon is a simple form of digester technology suitable for liquid manure with less than 3-percent solids. For this type of digester, an impermeable floating cover of industrial fabric covers all or part of the lagoon. A concrete footing along the edge of the lagoon holds the cover in place with an airtight seal. Methane produced in the lagoon collects under the cover. A suction pipe extracts the gas for use. Covered lagoon digesters require large lagoon volumes and a warm climate. Covered lagoons have low capital cost, but these systems are not suitable for locations in cooler climates or locations where a high water table exists.

A **complete mix digester** converts organic waste to biogas in a heated tank above or below ground. A mechanical or gas mixer keeps the solids in suspension. Complete mix digesters are expensive to construct and cost more than plug-flow digesters to operate and maintain.

Complete mix digesters are suitable for larger manure volumes having solids concentration of 3 percent to 10 percent. The reactor is a circular steel or poured concrete container. During the digestion process, the manure slurry is continuously mixed to keep the solids in suspension. Biogas accumulates at the top of the digester. The biogas can be used as fuel for an engine-generator to produce electricity or as boiler fuel to produce steam. Using waste heat from the engine or boiler to warm the slurry in the digester reduces retention time to less than 20 days.

Plug-flow digesters are suitable for ruminant animal manure that has a solids concentration of 11 percent to 13 percent. A typical design for a plug-flow system includes a manure collection system, a mixing pit and the digester itself. In the mixing pit, the addition of water adjusts the proportion of solids in the manure slurry to the optimal consistency. The digester is a long, rectangular container, usually built below-grade, with an airtight, expandable cover.

New material added to the tank at one end pushes older material to the opposite end. Coarse solids in ruminant manure form a viscous material as they are digested, limiting solids separation in the digester tank. As a result, the material flows through the tank in a "plug." Average retention time (the time a manure "plug" remains in the digester) is 20 to 30 days.
Anaerobic digestion of the manure slurry releases biogas as the material flows through the digester. A flexible, impermeable cover on the digester traps the gas. Pipes beneath the cover
carry the biogas from the digester to an engine-generator set.

A plug-flow digester requires minimal maintenance. Waste heat from the engine-generator can be used to heat the digester. Inside the digester, suspended heating pipes allow hot water to circulate. The hot water heats the digester to keep the slurry at 25°C to 40°C (77°F to 104°F), a temperature range suitable for methane-producing bacteria. The hot water can come from recovered waste heat from an engine generator fueled with digester gas or from burning digester gas directly in a boiler.

The Process of Anaerobic Digestion

The process of anaerobic digestion occurs in a sequence of stages involving distinct types of bacteria. Hydrolytic and fermentative bacteria first break down the carbohydrates, proteins and fats present in biomass feedstock into fatty acids, alcohol, carbon dioxide, hydrogen, ammonia and sulfides. This stage is called "hydrolysis" (or "liquefaction").

Next, acetogenic (acid-forming) bacteria further digest the products of hydrolysis into acetic acid, hydrogen and carbon dioxide. Methanogenic (methane-forming) bacteria then convert these products into biogas.

The combustion of digester gas can supply useful energy in the form of hot air, hot water or steam. After filtering and drying, digester gas is suitable as fuel for an internal combustion engine, which, combined with a generator, can produce electricity. Future applications of digester gas may include electric power production from gas turbines or fuel cells. Digester gas can substitute for natural gas or propane in space heaters, refrigeration equipment, cooking stoves or other equipment. Compressed digester gas can be used as an alternative transportation fuel.

Manure Digesters

Anaerobic digestion and power generation at the farm level began in the United States in the early 1970s. Several universities conducted basic digester research. In 1978, Cornell University built an early plug-flow digester designed with a capacity to digest the manure from 60 cows.

In the 1980s, new federal tax credits spurred the construction of about 120 plug-flow digesters in the United States. However, many of these systems failed because of poor design or faulty construction. Adverse publicity about system failures and operational problems meant that fewer anaerobic digesters were being built by the end of the decade. High digester cost and declining farm land values reduced the digester industry to a small number of suppliers.

The Tillamook Digester Facility (MEAD Project) began operation in 2003. The facility is located on a site once occupied by a Navy blimp hanger on property owned by the Port of Tillamook Bay. The facility consists of two 400,000-gallon digester cells. The facility uses the biogas to run two Caterpillar engines, each coupled to a 200 kilowatt generator. The facility sells its electric output to the Tillamook PUD. Manure is brought to the facility by truck from participating dairy farms in the Tillamook area.

Wastewater

Municipal sewage contains organic biomass solids, and many wastewater treatment plants use anaerobic digestion to reduce the volume of these solids. Anaerobic digestion stabilizes sewage sludge and destroys pathogens. Sludge digestion produces biogas containing 60-percent to 70-percent methane, with an energy content of about 600 Btu per cubic foot.

Most wastewater treatment plants that use anaerobic digesters burn the gas for heat to maintain digester temperatures and to heat building space. Unused gas is burned off as waste but could be used for fuel in an engine-generator or fuel cell to produce electric power.

A fuel cell at the Columbia Boulevard Wastewater Treatment Plant in Portland, Oregon, converts digester gas into electricity. The fuel cell began producing power in July 1999. The Columbia Boulevard fuel cell will produce an estimated 1,500,000 kilowatt-hours of electricity each year

Landfill Gas

The same anaerobic digestion process that produces biogas from animal manure and wastewater occurs naturally underground in landfills. Most landfill gas results from the decomposition of cellulose contained in municipal and industrial solid waste. Unlike animal manure digesters, which control the anaerobic digestion process, the digestion occurring in landfills is an uncontrolled process of biomass decay.

The efficiency of the process depends on the waste composition and moisture content of the landfill, cover material, temperature and other factors. The biogas released from landfills, commonly called "landfill gas," is typically 50-percent methane, 45-percent carbon dioxide and 5-percent other gases. The energy content of landfill gas is 400 to 550 Btu per cubic foot.

Capturing landfill gas before it escapes to the atmosphere allows for conversion to useful energy. A landfill must be at least 40 feet deep and have at least one million tons of waste in place for landfill gas collection and power production to be technically feasible.

A landfill gas-to-energy system consists of a series of wells drilled into the landfill. A piping system connects the wells and collects the gas. Dryers remove moisture from the gas, and filters remove impurities. The gas typically fuels an engine-generator set or gas turbine to produce electricity. The gas also can fuel a boiler to produce heat or steam. Further gas cleanup improves biogas to pipeline quality, the equivalent of natural gas. Reforming the gas to hydrogen would make possible the production of electricity using fuel cell technology.

ATTACHMENT D:

US EPA AP-42
Section 3.2 Natural Gas Fired Reciprocating Engines

3.2 Natural Gas-fired Reciprocating Engines

3.2.1 General[1-3]

Most natural gas-fired reciprocating engines are used in the natural gas industry at pipeline compressor and storage stations and at gas processing plants. These engines are used to provide mechanical shaft power for compressors and pumps. At pipeline compressor stations, engines are used to help move natural gas from station to station. At storage facilities, they are used to help inject the natural gas into high pressure natural gas storage fields. At processing plants, these engines are used to transmit fuel within a facility and for process compression needs (e.g., refrigeration cycles). The size of these engines ranges from 50 brake horsepower (bhp) to 11,000 bhp. In addition, some engines in service are 50 - 60 years old and consequently have significant differences in design compared to newer engines, resulting in differences in emissions and the ability to be retrofitted with new parts or controls.

At pipeline compressor stations, reciprocating engines are used to power reciprocating compressors that move compressed natural gas (500 - 2000 psig) in a pipeline. These stations are spaced approximately 50 to 100 miles apart along a pipeline that stretches from a gas supply area to the market area. The reciprocating compressors raise the discharge pressure of the gas in the pipeline to overcome the effect of frictional losses in the pipeline upstream of the station, in order to maintain the required suction pressure at the next station downstream or at various downstream delivery points. The volume of gas flowing and the amount of subsequent frictional losses in a pipeline are heavily dependent on the market conditions that vary with weather and industrial activity, causing wide pressure variations. The number of engines operating at a station, the speed of an individual engine, and the amount of individual engine horsepower (load) needed to compress the natural gas is dependent on the pressure of the compressed gas received by the station, the desired discharge pressure of the gas, and the amount of gas flowing in the pipeline. Reciprocating compressors have a wider operating bandwidth than centrifugal compressors, providing increased flexibility in varying flow conditions. Centrifugal compressors powered by natural gas turbines are also used in some stations and are discussed in another section of this document.

A compressor in storage service pumps gas from a low-pressure storage field (500 - 800 psig) to a higher pressure transmission pipeline (700 - 1000 psig) and/or pumps gas from a low-pressure transmission line (500 - 800 psig) to a higher pressure storage field (800 - 2000 psig).

Storage reciprocating compressors must be flexible enough to allow operation across a wide band of suction and discharge pressures and volume variations. The compressor must be able to compress at high compression ratios with low volumes and compress at low compression ratios with high volumes. These conditions require varying speeds and load (horsepower) conditions for the reciprocating engine powering the reciprocating compressor.

Reciprocating compressors are used at processing plants for process compression needs (e.g. refrigeration cycles). The volume of gas compressed varies, but the pressure needed for the process is more constant than the other two cases mentioned above.

3.2.2 Process Description[1-3]

Natural gas-fired reciprocating engines are separated into three design classes: 2-cycle (stroke) lean-burn, 4-stroke lean-burn, and 4-stroke rich-burn. Two-stroke engines complete the power cycle in a single crankshaft revolution as compared to the two crankshaft revolutions required for 4-stroke engines. All engines in these categories are spark-ignited.

In a 2-stroke engine, the air-to-fuel charge is injected with the piston near the bottom of the power stroke. The intake ports are then covered or closed, and the piston moves to the top of the cylinder, compressing the charge. Following ignition and combustion, the power stroke starts with the downward movement of the piston. As the piston reaches the bottom of the power stroke, exhaust ports or valves are opened to exhaust, or scavenge, the combustion products, and a new air-to-fuel charge is injected. Two-stroke engines may be turbocharged using an exhaust-powered turbine to pressurize the charge for injection into the cylinder and to increase cylinder scavenging. Non-turbocharged engines may be either blower scavenged or piston scavenged to improve removal of combustion products. Historically, 2-stroke designs have been widely used in pipeline applications. However, current industry practices reflect a decline in the usage of new 2-stroke engines for stationary applications.

Four-stroke engines use a separate engine revolution for the intake/compression cycle and the power/exhaust cycle. These engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or turbocharged, using an exhaust-driven turbine to pressurize the charge. Turbocharged units produce a higher power output for a given engine displacement, whereas naturally aspirated units have lower initial costs and require less maintenance.

Rich-burn engines operate near the stoichiometric air-to-fuel ratio (16:1) with exhaust excess oxygen levels less than 4 percent (typically closer to 1 percent). Additionally, it is likely that the emissions profile will be considerably different for a rich-burn engine at 4 percent oxygen than when operated closer to stoichiometric conditions. Considerations such as these can impact the quantitative value of the emission factor presented. It is also important to note that while rich-burn engines may operate, by definition, with exhaust oxygen levels as high as 4 percent, in reality, most will operate within plus or minus 1 air-to-fuel ratio of stoichiometry. Even across this narrow range, emissions will vary considerably, sometimes by more than an order of magnitude. Air-to-fuel ratios were not provided in the gathered emissions data used to develop the presented factors.

Lean-burn engines may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12 percent or greater. The air to fuel ratios of lean-burn engines range from 20:1 to 50:1 and are typically higher than 24:1. The exhaust excess oxygen levels of lean-burn engines are typically around 8 percent, ranging from 4 to 17 percent. Some lean-burn engines are characterized as clean-burn engines. The term “clean-burn” technology is a registered trademark of Cooper Energy Systems and refers to engines designed to reduce NO_x by operating at high air-to-fuel ratios. Engines operating at high air-to-fuel ratios (greater than 30:1) may require combustion modification to promote stable combustion with the high excess air. These modifications may include a turbo charger or a precombustion chamber (PCC). A turbo charger is used to force more air into the combustion chamber, and a PCC is used to ignite a fuel-rich mixture that propagates into the main cylinder and ignites the very lean combustion charge. Lean-burn engines typically have lower oxides of nitrogen (NO_x) emissions than rich-burn engines.

3.2.3 Emissions

The primary criteria pollutants from natural gas-fired reciprocating engines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC). The formation of nitrogen oxides is exponentially related to combustion temperature in the engine cylinder. The other pollutants, CO and VOC species, are primarily the result of incomplete combustion. Particulate matter (PM) emissions include trace amounts of metals, non-combustible inorganic material, and condensible, semi-volatile organics which result from volatized lubricating oil, engine wear, or from products of incomplete combustion. Sulfur oxides are very low since sulfur compounds are removed from natural gas at processing plants. However, trace amounts of sulfur containing odorant are added to natural gas at city gates prior to distribution for the purpose of leak detection.

It should be emphasized that the actual emissions may vary considerably from the published emission factors due to variations in the engine operating conditions. This variation is due to engines operating at different conditions, including air-to-fuel ratio, ignition timing, torque, speed, ambient temperature, humidity, and other factors. It is not unusual to test emissions from two identical engines in the same plant, operated by the same personnel, using the same fuel, and have the test results show significantly different emissions. This variability in the test data is evidenced in the high relative standard deviation reported in the data set.

3.2.3.1 Nitrogen Oxides -

Nitrogen oxides are formed through three fundamentally different mechanisms. The principal mechanism of NO_x formation with gas-fired engines is thermal NO_x. The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in high-temperature regions in the cylinder where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface. The second mechanism, called prompt NO_x, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible compared to the level of NO_x formed through the thermal NO_x mechanism. The third mechanism, fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically bound fuel nitrogen (although some molecular nitrogen is present).

Essentially all NO_x formed in natural gas-fired reciprocating engines occurs through the thermal NO_x mechanism. The formation of NO_x through the prompt NO_x mechanism may be significant only under highly controlled situations in rich-burn engines when the thermal NO_x mechanism is suppressed. The rate of NO_x formation through the thermal NO_x mechanism is highly dependent upon the stoichiometric ratio, combustion temperature, and residence time at the combustion temperature. Maximum NO_x formation occurs through the thermal NO_x mechanism near the stoichiometric air-to-fuel mixture ratio since combustion temperatures are greatest at this air-to-fuel ratio.

3.2.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions are both products of incomplete combustion. CO results when there is insufficient residence time at high temperature to complete the final step in hydrocarbon oxidation. In reciprocating engines, CO emissions may indicate early quenching of combustion gases on cylinder walls or valve surfaces. The oxidation of CO to carbon dioxide (CO_2) is a slow reaction compared to most hydrocarbon oxidation reactions.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds that are photoreactive in the atmosphere. VOC occur when some of the gas remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carryover, unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. Partially burned hydrocarbons result from poor air-to-fuel mixing prior to, or during, combustion, or incorrect air-to-fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system. Also, low cylinder temperature may yield partially burned hydrocarbons due to excessive cooling through the walls, or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed.

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a] (SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES (Continued)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Acenaphthylene[k]	5.53 E-06	C
Acetaldehyde[k,l]	8.36 E-03	A
Acrolein[k,l]	5.14 E-03	A
Benzene[k]	4.40 E-04	A
Benzo(b)fluoranthene[k]	1.66 E-07	D
Benzo(e)pyrene[k]	4.15 E-07	D
Benzo(g,h,i)perylene[k]	4.14 E-07	D
Biphenyl[k]	2.12 E-04	D
Butane	5.41 E-04	D
Butyr/Isobutyraldehyde	1.01 E-04	C
Carbon Tetrachloride[k]	<3.67 E-05	E
Chlorobenzene[k]	<3.04 E-05	E
Chloroethane	1.87 E-06	D
Chloroform[k]	<2.85 E-05	E
Chrysene[k]	6.93 E-07	C
Cyclopentane	2.27 E-04	C
Ethane	1.05 E-01	C
Ethylbenzene[k]	3.97 E-05	B
Ethylene Dibromide[k]	<4.43 E-05	E
Fluoranthene[k]	1.11 E-06	C
Fluorene[k]	5.67 E-06	C
Formaldehyde[k,l]	5.28 E-02	A
Methanol[k]	2.50 E-03	B
Methylcyclohexane	1.23 E-03	C
Methylene Chloride[k]	2.00 E-05	C
n-Hexane[k]	1.11 E-03	C
n-Nonane	1.10 E-04	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES
(Continued)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
n-Octane	3.51 E-04	C
n-Pentane	2.60 E-03	C
Naphthalene[k]	7.44 E-05	C
PAH[k]	2.69 E-05	D
Phenanthrene[k]	1.04 E-05	D
Phenol[k]	2.40 E-05	D
Propane	4.19 E-02	C
Pyrene[k]	1.36 E-06	C
Styrene[k]	<2.36 E-05	E
Tetrachloroethane[k]	2.48 E-06	D
Toluene[k]	4.08 E-04	B
Vinyl Chloride[k]	1.49 E-05	C
Xylene[k]	1.84 E-04	B

[a] Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM10, "uncontrolled" means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, "uncontrolled" means no oxidation control; the data set may include units with control techniques used for NOx control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM-10 = Particulate Matter ≤ 10 microns (μm) aerodynamic diameter. A "<" sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

[b] Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA Method 19. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$\text{lb/hp-hr} = (\text{lb/MMBtu})(\text{heat input, MMBtu/hr})(\text{1/operating HP, 1/hp})$$

[c] Emission tests with unreported load conditions were not included in the data set.

[d] Based on 99.5% conversion of the fuel carbon to CO_2. CO_2 [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10^6 scf, and

h = heating value of natural gas (assume 1020 Btu/scf at 60°F).

[e] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content in natural gas of 2,000 gr/10^6scf.

[f] Emission factor for TOC is based on measured emission levels from 22 source tests.

[g] Emission factor for methane is determined by subtracting the VOC and ethane emission factors from the TOC emission factor. Measured emission factor for methane compares well with the calculated emission factor, 1.31 lb/MMBtu vs. 1.25 lb/MMBtu, respectively.

[h] VOC emission factor is based on the sum of the emission factors for all speciated organic compounds less ethane and methane.

[i] Considered ≤ 1 μm in aerodynamic diameter. Therefore, for filterable PM emissions, PM10(filterable) = PM2.5(filterable).

[j] PM Condensable = PM Condensable Inorganic + PM-Condensable Organic

[k] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

[l] For lean burn engines, aldehyde emissions quantification using CARB 430 may reflect interference with the sampling compounds due to the nitrogen concentration in the stack. The presented emission factor is based on FTIR measurements. Emissions data based on CARB 430 are available in the background report.

ATTACHMENT E:

NSPS 40CFR60 SUBPART JJJJ
(SPARK IGNITED RECIPROCATING ENGINES)

Federal Register

Friday,
January 18, 2008

Part III

Environmental Protection Agency

40 CFR Parts 60, 63, 85 et al.

Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; Final Rule

not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Stationary internal combustion engine test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that test stationary ICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Subpart means 40 CFR part 60, subpart JJJJ.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Volatile organic compounds means volatile organic compounds as defined in 40 CFR 51.100(s).

Voluntary certification program means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable.

Tables to Subpart JJJJ of Part 60

TABLE 1 TO SUBPART JJJJ OF PART 60.—NO_X, CO, AND VOC EMISSION STANDARDS FOR STATIONARY NON-EMERGENCY SI ENGINES ≥100 HP (EXCEPT GASOLINE AND RICH BURN LPG), STATIONARY SI LANDFILL/DIGESTER GAS ENGINES, AND STATIONARY EMERGENCY ENGINES >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC[d]	NO_X	CO	VOC[d]
Non-Emergency SI Natural Gas[b] and Non-Emergency SI Lean Burn LPG[b].	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG.	500≥HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500=≥HP<1,350).	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≥HP<1,350).	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500≥HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25>HP<130	1/1/2009	[c]10	387	N/A	N/A	N/A	N/A
			2.0	4.0	1.0	160	540	86
	HP≥130							

[a] Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O_2.

[b] Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2A do not have to comply with the CO emission standards of Table 1 of this subpart.

[c] The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_X+HC.

[d] For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

TABLE 2 TO SUBPART JJJJ OF PART 60.—REQUIREMENTS FOR PERFORMANCE TESTS

[As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to § 60.4244.	a. limit the concentration of NO_X in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A or ASTM Method D6522–00(2005)[a].	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. Determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.	

Stationary SI engines with a maximum engine power between 100 HP and 500 HP that are natural gas engines or lean burn engines using LPG that are manufactured after January 1, 2011, must limit their exhaust emissions of NO_X to 1.0 g/HP-hr, emissions of CO to 2.0 g/HP-hr, and emissions of VOC to 0.7 g/HP-hr. Again, owners and operators may as an alternative limit their exhaust emissions of NO_X to 82 ppmvd at 15 percent O_2, emissions of CO to 270 ppmvd at 15 percent O_2, and emissions of VOC to 60 ppmvd at 15 percent O_2 instead of the g/HP-hr limits.

Owners and operators who purchase stationary SI engines with a maximum engine power greater than or equal to 500 HP that are natural gas engines or lean burn engines using LPG that are manufactured after July 1, 2007, must limit their exhaust emissions of NO_X to 2.0 g/HP-hr, emissions of CO to 4.0 g/HP-hr, and emissions of VOC to 1.0 g/HP-hr, except that these standards apply to lean burn engines between 500 and 1,350 HP manufactured after January 1, 2008. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit their exhaust emissions of NO_X to 160 ppmvd at 15 percent O_2, emissions of CO to 540 ppmvd at 15 percent O_2, and emissions of VOC to 86 ppmvd at 15 percent O_2.

Stationary SI engines with a maximum engine power greater than or equal to 500 HP that are natural gas engines or lean burn engines using LPG that are manufactured after July 1, 2010, must limit their exhaust emissions of NO_X to 1.0 g/HP-hr, emissions of CO to 2.0 g/HP-hr, and emissions of VOC to 0.7 g/HP-hr. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit their exhaust emissions of NO_X to 82 ppmvd at 15 percent O_2, emissions of CO to 270 ppmvd at 15 percent O_2, and emissions of VOC to 60 ppmvd at 15 percent O_2.

Engine manufacturers may voluntarily certify their stationary non-emergency SI natural gas engines greater than or equal to 100 HP and lean burn LPG engines greater than or equal to 100 HP, but the certification is not required by the rule. Additionally, for natural gas engines below 500 HP manufactured prior to January 1, 2011, and natural gas engines greater than or equal to 500 HP manufactured prior to July 1, 2010, engine manufacturers may choose to certify their engines to the standards for non-severe duty engines in 40 CFR part 1048 (see Table 2 of this preamble).

A summary of the emission standards that apply to stationary non-emergency SI natural gas engines greater than or equal to 100 HP and lean burn LPG engines greater than or equal to 100 HP are shown in Table 4 of this preamble.

For lean burn LPG engines greater than or equal to 100 HP, manufacturers may certify these engines to the certification emission standards in 40 CFR part 1048 instead of the emission standards shown in Table 4 of this preamble.

TABLE 4.—NO_X, CO, AND VOC EMISSION STANDARDS FOR STATIONARY SI ENGINES ≥100 HP (EXCEPT GASOLINE AND RICH BURN LPG), STATIONARY SI LANDFILL/DIGESTER GAS ENGINES, AND STATIONARY EMERGENCY ENGINES >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC	NO_X	CO	VOC
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG.	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG.	500≥HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≥HP<1,350).	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≥HP<1,350).	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas lean burn	500≥HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25>HP<130	1/1/2009	[b]10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

[a] Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O_2.

[b] The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_X+HC.

e. Stationary SI Landfill/Digester Gas Engines. Owners and operators who purchase stationary landfill or digester SI engines that are manufactured after July 1, 2007, that are greater than or equal to 500 HP must limit their exhaust emissions of NO_X to 3.0 g/HP-hr, emissions of CO to 5.0 g/HP-hr, and emissions of VOC to 1.0 g/HP-hr, except that these standards apply to lean burn engines between 500 and 1,350 HP manufactured after January 1, 2008. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit their exhaust emissions of NO_X to 220 ppmvd at 15 percent O_2, emissions of CO to 610 ppmvd at 15 percent O_2, and emissions of VOC to 80 ppmvd at 15 percent O_2.

Stationary landfill and digester gas SI engines greater than or equal to 500 HP that are manufactured after July 1, 2010, must limit their exhaust emissions of NO_X to 2.0 g/HP-hr, emissions of CO to 5.0 g/HP-hr, and emissions of VOC to 1.0 g/HP-hr. Instead of complying with limits in terms of g/HP-hr, owners and operators may limit their exhaust emissions of NO_X to 150 ppmvd at 15 percent O_2, emissions of CO to 610 ppmvd at 15 percent O_2, and emissions of VOC to 80 ppmvd at 15 percent O_2.