

SUBCHAPTER W: TURBINES AND ENGINES
§§106.511 - 106.513
Effective August 16, 2012

§106.511. Portable and Emergency Engines and Turbines.

Internal combustion engine and gas turbine driven compressors, electric generator sets, and water pumps, used only for portable, emergency, and/or standby services are permitted by rule, provided that the maximum annual operating hours shall not exceed 10% of the normal annual operating schedule of the primary equipment; and all electric motors. For purposes of this section, “standby” means to be used as a “substitute for” and not “in addition to” other equipment.

Adopted August 9, 2000

Effective September 4, 2000

§106.512. Stationary Engines and Turbines.

Gas or liquid fuel-fired stationary internal combustion reciprocating engines or gas turbines that operate in compliance with the following conditions of this section are permitted by rule.

(1) The facility shall be registered by submitting the commission’s Form PI-7, Table 29 for each proposed reciprocating engine, and Table 31 for each proposed gas turbine to the commission’s Office of Permitting, Remediation, and Registration in Austin within ten days after construction begins. Engines and turbines rated less than 240 horsepower (hp) need not be registered, but must meet paragraphs (5) and (6) of this section, relating to fuel and protection of air quality. Engine hp rating shall be based on the engine manufacturer’s maximum continuous load rating at the lesser of the engine or driven equipment’s maximum published continuous speed. A rich-burn engine is a gas-fired spark-ignited engine that is operated with an exhaust oxygen content less than 4.0% by volume. A lean-burn engine is a gas-fired spark-ignited engine that is operated with an exhaust oxygen content of 4.0% by volume, or greater.

(2) For any engine rated 500 hp or greater, subparagraphs (A) - (C) of this paragraph shall apply.

(A) The emissions of nitrogen oxides (NO_x) shall not exceed the following limits:

(i) 2.0 grams per horsepower-hour (g/hp-hr) under all operating conditions for any gas-fired rich-burn engine;

(ii) 2.0 g/hp-hr at manufacturer's rated full load and speed, and other operating conditions, except 5.0 g/hp-hr under reduced speed, 80-100% of full torque conditions, for any spark-ignited, gas-fired lean-burn engine, or any compression-ignited dual fuel-fired engine manufactured new after June 18, 1992;

(iii) 5.0 g/hp-hr under all operating conditions for any spark-ignited, gas-fired, lean-burn two-cycle or four-cycle engine or any compression-ignited dual fuel-fired engine rated 825 hp or greater and manufactured after September 23, 1982, but prior to June 18, 1992;

(iv) 5.0 g/hp-hr at manufacturer's rated full load and speed and other operating conditions, except 8.0 g/hp-hr under reduced speed, 80-100% of full torque conditions for any spark-ignited, gas-fired, lean-burn four-cycle engine, or any compression-ignited dual fuel-fired engine that:

(I) was manufactured prior to June 18, 1992, and is rated less than 825 hp; or

(II) was manufactured prior to September 23, 1982;

(v) 8.0 g/hp-hr under all operating conditions for any spark-ignited, gas-fired, two-cycle lean-burn engine that:

(I) was manufactured prior to June 18, 1992, and is rated less than 825 hp; or

(II) was manufactured prior to September 23, 1982;

(vi) 11.0 g/hp-hr for any compression-ignited liquid-fired engine.

(B) For such engines which are spark-ignited gas-fired or compression-ignited dual fuel-fired, the engine shall be equipped as necessary with an automatic air-fuel ratio (AFR) controller which maintains AFR in the range required to meet the emission limits of subparagraph (A) of this paragraph. An AFR controller shall be deemed necessary for any engine controlled with a non-selective catalytic reduction (NSCR) converter and for applications where the fuel heating value varies more than \pm 50 British thermal unit/standard cubic feet from the design lower heating value of the fuel. If an NSCR converter is used to reduce NO_x, the automatic controller shall operate on exhaust oxygen control.

(C) Records shall be created and maintained by the owner or operator for a period of at least two years, made available, upon request, to the

commission and any local air pollution control agency having jurisdiction, and shall include the following:

(i) documentation for each AFR controller, manufacturer's, or supplier's recommended maintenance that has been performed, including replacement of the oxygen sensor as necessary for oxygen sensor-based controllers. The oxygen sensor shall be replaced at least quarterly in the absence of a specific written recommendation;

(ii) documentation on proper operation of the engine by recorded measurements of NO_x and carbon monoxide (CO) emissions as soon as practicable, but no later than seven days following each occurrence of engine maintenance which may reasonably be expected to increase emissions, changes of fuel quality in engines without oxygen sensor-based AFR controllers which may reasonably be expected to increase emissions, oxygen sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x and CO concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x and CO analyzers shall also be acceptable for this documentation;

(iii) documentation within 60 days following initial engine start-up and biennially thereafter, for emissions of NO_x and CO, measured in accordance with United States Environmental Protection Agency (EPA) Reference Method 7E or 20 for NO_x and Method 10 for CO. Exhaust flow rate may be determined from measured fuel flow rate and EPA Method 19. California Air Resources Board Method A-100 (adopted June 29, 1983) is an acceptable alternate to EPA test methods. Modifications to these methods will be subject to the prior approval of the Source and Mobile Monitoring Division of the commission. Emissions shall be measured and recorded in the as-found operating condition; however, compliance determinations shall not be established during start-up, shutdown, or under breakdown conditions. An owner or operator may submit to the appropriate regional office a report of a valid emissions test performed in Texas, on the same engine, conducted no more than 12 months prior to the most recent start of construction date, in lieu of performing an emissions test within 60 days following engine start-up at the new site. Any such engine shall be sampled no less frequently than biennially (or every 15,000 hours of elapsed run time, as recorded by an elapsed run time meter) and upon request of the executive director. Following the initial compliance test, in lieu of performing stack sampling on a biennial calendar basis, an owner or operator may elect to install and operate an elapsed operating time meter and shall test the engine within 15,000 hours of engine operation after the previous emission test. The owner or operator who elects to test on an operating hour schedule shall submit in writing, to the appropriate regional office, biennially after initial sampling, documentation of the actual recorded hours of engine

operation since the previous emission test, and an estimate of the date of the next required sampling.

(3) For any gas turbine rated 500 hp or more, subparagraphs (A) and (B) of this paragraph shall apply.

(A) The emissions of NO_x shall not exceed 3.0 g/hp-hr for gas-firing.

(B) The turbine shall meet all applicable NO_x and sulfur dioxide (SO₂) (or fuel sulfur) emissions limitations, monitoring requirements, and reporting requirements of EPA New Source Performance Standards Subpart GG--Standards of Performance for Stationary Gas Turbines. Turbine hp rating shall be based on turbine base load, fuel lower heating value, and International Standards Organization Standard Day Conditions of 59 degrees Fahrenheit, 1.0 atmosphere and 60% relative humidity.

(4) Any engine or turbine rated less than 500 hp or used for temporary replacement purposes shall be exempt from the emission limitations of paragraphs (2) and (3) of this section. Temporary replacement engines or turbines shall be limited to a maximum of 90 days of operation after which they shall be removed or rendered physically inoperable.

(5) Gas fuel shall be limited to: sweet natural gas or liquid petroleum gas, fuel gas containing no more than ten grains total sulfur per 100 dry standard cubic feet, or field gas. If field gas contains more than 1.5 grains hydrogen sulfide or 30 grains total sulfur compounds per 100 standard cubic feet (sour gas), the engine owner or operator shall maintain records, including at least quarterly measurements of fuel hydrogen sulfide and total sulfur content, which demonstrate that the annual SO₂ emissions from the facility do not exceed 25 tons per year (tpy). Liquid fuel shall be petroleum distillate oil that is not a blend containing waste oils or solvents and contains less than 0.3% by weight sulfur.

(6) There will be no violations of any National Ambient Air Quality Standard (NAAQS) in the area of the proposed facility. Compliance with this condition shall be demonstrated by one of the following three methods:

(A) ambient sampling or dispersion modeling accomplished pursuant to guidance obtained from the executive director. Unless otherwise documented by actual test data, the following nitrogen dioxide (NO₂)/NO_x ratios shall be used for modeling NO₂ NAAQS;

<u>Device</u>	<u>NO_x Emission Rate (Q)</u> <u>g/hp-hr</u>	<u>NO₂/NO_x</u> <u>Ratio</u>
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IC Engine	Less than 2.0		0.4
IC Engine	2.0 thru 10.0		0.15
		+(0.5/Q)	
IC Engine	Greater than 10.0		0.2
Turbines			0.25
IC Engine with catalytic converter			0.85

(B) all existing and proposed engine and turbine exhausts are released to the atmosphere at a height at least twice the height of any surrounding obstructions to wind flow. Buildings, open-sided roofs, tanks, separators, heaters, covers, and any other type of structure are considered as obstructions to wind flow if the distance from the nearest point on the obstruction to the nearest exhaust stack is less than five times the lesser of the height, Hb, and the width, Wb, where:

Hb = maximum height of the obstruction, and
 Wb = projected width of obstruction =

$$2\sqrt{\frac{LW}{3.141}}$$

where:

L = length of obstruction
 W = width of obstruction

(C) the total emissions of NO_x (nitrogen oxide plus NO₂) from all existing and proposed facilities on the property do not exceed the most restrictive of the following:

(i) 250 tpy;

(ii) the value (0.3125 D) tpy, where D equals the shortest distance in feet from any existing or proposed stack to the nearest property line.

(7) Upon issuance of a standard permit for electric generating units, registrations under this section for engines or turbines used to generate electricity will no longer be accepted, except for:

(A) engines or turbines used to provide power for the operation of facilities registered under the Air Quality Standard Permit for Concrete Batch Plants;

(B) engines or turbines satisfying the conditions for facilities permitted by rule under Subchapter E of this title (relating to Aggregate and Pavement); or

(C) engines or turbines used exclusively to provide power to electric pumps used for irrigating crops.

Adopted May 23, 2001

Effective June 13, 2001

§106.513. Natural Gas-Fired Combined Heat and Power Units.

(a) Applicability.

(1) This section applies to combined heat and power (CHP) units that are powered by pipeline-quality natural gas-fired engines, including turbines. This section also authorizes any fugitive components associated with a CHP unit authorized by this section.

(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.

(b) Definitions.

(1) Combined heat and power (CHP) unit--A collection of facilities and other equipment that generally consists of an electric generating unit (EGU) and a means of extracting energy from the EGU for useful purposes other than electricity generation, such as heating or cooling. A CHP unit does not include facilities for generating additional electricity after the EGU. Equipment that is not a source of emissions itself but also extracts energy from the exhaust flow to create electricity is not a facility and may be used in addition to a CHP unit authorized by this section.

(2) Pipeline-quality natural gas--A naturally occurring fluid mixture of hydrocarbons (composed predominantly of methane, with lesser amounts of ethane, propane, nitrogen, carbon dioxide, and trace amounts of hydrogen sulfide) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and that is provided by a supplier through a pipeline. Pipeline-quality natural gas must either be composed of at least 70% methane by volume, or have a gross calorific value between 950 and 1,100 British thermal units (BTU) per standard cubic foot. Sour gas as defined

in §101.1 of this title (relating to Definitions) is not pipeline-quality natural gas for purposes of this section.

(c) General Requirements.

(1) A CHP unit must be registered with the commission using the appropriate PI-7 form or an approved electronic registration method before start of construction. A CHP unit at a residential location that generates less than 20 kilowatts(kW) of electricity does not require registration and does not have to meet any other requirements of this section except subsection (a) of this section and paragraph (2) of this subsection.

(2) For a CHP unit to be eligible for authorization under this section, the heat recovered must equal at least 20% of the total heat energy output of the CHP unit. This requirement must be met continuously based on any calendar week of operation except for no more than two weeks in a rolling 52-week period if operation of the EGU component is necessary due to lack of available electricity.

(3) No owner or operator of a CHP unit that is required to register under this section may begin construction and/or operation without first obtaining written approval from the executive director.

(4) Except for oxidation-reduction (three-way) catalysts on rich-burn engines, and oxidation catalyst controls as required by subsection (d)(3) or (4) of this section, add-on controls may not be used to comply with the emission standards of this section.

(5) Any individual CHP unit, or any group of units meeting paragraph (7)(B) of this subsection, may not exceed 15 megawatts (MW) in capacity.

(6) Only one permit by rule (PBR) for Natural Gas-Fired CHP Units per this section may be registered at a site.

(7) No more than one CHP unit may be authorized at a site under this section, except as follows:

(A) Any units with a capacity of less than 20 kW are not limited in number, or restricted in location. Units with a capacity of less than 20 kW are not required to be considered when applying subparagraphs (B) or (C) of this paragraph.

(B) Multiple units may be authorized under this PBR if all stack emission points associated with the units are located within a circular area with a radius of 200 feet, and the total EGU capacity of the group is not greater than 15 MW.

(C) Multiple units may be authorized under this PBR if all stack emission points associated with the units are separated by a distance of at least 900 feet. Multiple groups of units meeting the requirements of subparagraph (B) of this paragraph may be authorized if the groups' emission points are separated by a distance of at least 900 feet.

(8) Notwithstanding fuel restrictions elsewhere in this section, during an emergency, this PBR authorizes the use of propane, liquefied petroleum gas, gasoline, diesel, or fuel oil as an approved fuel for not more than 720 hours in any 365-day period. This PBR also authorizes brief use of these emergency fuels as needed for purposes of maintenance or testing, for not more than two hours in any seven-day period.

(d) Emission Standards and Control Requirements.

(1) Notwithstanding paragraphs (2), (3), or (4) of this subsection, a CHP unit with a capacity less than 20 kW is not subject to a nitrogen oxides (NO_x) or carbon monoxide (CO) emission standard, and is not subject to the requirement for an oxidation catalyst control device.

(2) A CHP unit or any combination of units with a total capacity greater than or equal to 20 kW, but less than or equal to 8 MW, must meet the following emission standards: 1.0 pound of NO_x per megawatt-hour (lb NO_x/MWh); and 9.0 lb CO/MWh.

(3) Except as provided in paragraph (4) of this subsection, a CHP unit or any combination of units with a total capacity greater than 8 MW must meet the following emission standards: 0.7 lb NO_x/MWh; and 9.0 lb CO/MWh. A CHP unit or units under this paragraph must also be equipped with an oxidation catalyst control device that maintains a minimum of 70% control of volatile organic compounds (VOC) in the CHP unit exhaust stream.

(4) Any combination of CHP units with a total capacity greater than 8 MW that are at least 900 feet apart from one another must meet the following emission standards and control requirements. For the purposes of this paragraph, any group of units under subsection (c)(7)(B) of this section is considered to be one unit when determining whether subparagraph (A) or (B) of this paragraph applies.

(A) CHP units with a capacity less than or equal to 8 MW: 1.0 pound of NO_x per megawatt-hour (lb NO_x/MWh); and 9.0 lb CO/MWh.

(B) CHP units with a capacity greater than 8 MW: 0.7 lb NO_x/MWh; and 9.0 lb CO/MWh. A CHP unit under this subparagraph must also be equipped with an oxidation catalyst control device that maintains a minimum of 70% control of VOC in the CHP unit exhaust stream.

(5) Compliance with the NO_x standards above may be achieved by taking credit for the heat recovered from the combustion unit. Credit will be at the rate of 1.0 MWh for each 3.4 million BTU of heat recovered. In order to claim this credit for CHP for units not sold and certified as an integrated package by the manufacturer, 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.

(e) Monitoring and Testing. CHP units authorized under this section with an electric generating capacity greater than or equal to 20 kW must meet the following requirements :

(1) Internal combustion engine-based CHP units (excluding turbines).

(A) The owner or operator shall initially analyze the emissions from the CHP unit using a portable analyzer no later than 180 calendar days after startup.

(B) After the initial testing specified by subparagraph (A) of this paragraph, the owner or operator shall conduct ongoing monitoring using a portable analyzer, once in the first half of each calendar year and once in the second half of each calendar year, with at least two months between tests. When a CHP unit did not operate for more than 1,000 hours in that half of the year, this test is not required.

(C) The portable analyzer must be operated at minimum in accordance with the manufacturer's instructions. A copy of the manufacturer's instructions shall be made available upon request. The NO_x and CO emissions must be converted into units of lb/MWh.

(2) Internal combustion engine-based CHP units and turbines. If the CHP unit is not certified to meet the emission standards of subsection (d) of this section by the manufacturer according to a United States Environmental Protection Agency (EPA) testing protocol, the unit must be tested within 90 days of startup for NO_x and CO according to appropriate EPA reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director and in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual. Tests must consist of three runs with a minimum of 30 minutes for each run or longer if required by the reference method. All engine- and turbine-based CHP units

designed to generate more than 375 kW must be retested by the above method after every 16,000 hours of operation, regardless of certification.

(3) All CHP units which are required by subsection (d)(3) or (4) of this section to have an oxidation catalyst control device shall be tested to verify compliance with the required 70% VOC control efficiency within 90 days of startup. In lieu of the above test, the 70% VOC control requirement shall be satisfied if the unit is tested for gaseous organic compounds and the reduction is at least 90%. The testing shall be conducted using EPA reference methods or equivalent alternative testing methods approved by the executive director and in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual. All units required to be equipped with an oxidation catalyst control device must also be retested after every 16,000 hours of operation.

(4) Except for rich-burn engines equipped with oxidation-reduction (three-way) catalysts, and units required to be equipped with an oxidation catalyst under subsection (d)(3) or (4) of this section, the uncontrolled source must demonstrate compliance with the emission standards in subsection (d) of this section.

(f) Recordkeeping. In addition to the minimum records required by §106.8 of this title (relating to Recordkeeping), the owner or operator must keep the following records:

(1) For the life of the CHP unit, the registration application and any additional representations made during the approval process to obtain the registration; and

(2) The owner or operator must keep the following records for at least two years and make them available to the TCEQ or any local pollution control program with jurisdiction upon request:

(A) A record of every one-week period of operation where the CHP unit did not comply with subsection (c)(2) of this section;

(B) All monitoring and testing data generated in compliance with subsection (e) of this section and in a format that shows the emission standards have been met;

(C) Records of CHP unit operation sufficient to demonstrate compliance with any applicable hour-based requirements of subsection (e) of this section;

(D) Records of maintenance described in subsection (g)(2) of this section; and (E) Records of the number of hours that any emergency fuel is used under

subsection (c)(8) of this section, and the reason why operating on an emergency fuel is necessary.

(g) Planned Maintenance, Startup, and Shutdown.

(1) This PBR authorizes all emissions from planned startup and shutdown activities associated with facilities that are authorized by this section.

(2) This PBR authorizes emissions from the following planned maintenance activities associated with facilities authorized by this section: routine maintenance including, but not limited to, filter changes, oxygen sensor replacements, overhauls, lubricant changes, spark plug changes, and emission control system maintenance.

Adopted July 25, 2012

Effective August 16, 2012