Texas Chapter 117 - Control of Air Pollution From Nitrogen Compounds

SUBCHAPTER B: COMBUSTION CONTROL AT MAJOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL SOURCES IN OZONE NONATTAINMENT AREAS

DIVISION 3: HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA MAJOR SOURCES
Adopted by TCEQ May 23, 2007 effective June 14, 2007 (7-27).
Submitted to EPA May 30, 2007.
Approved by EPA December 3, 2008 (73 FR 73562) effective January 2, 2009 (TXd97).
Amendatory language corrected January 14, 2009 (74 FR 1927) (TXd99).

Outline:

§117.354. Final Control Plan Procedures for Attainment Demonstration Emission Specifications. 7-27 (page 208), TXd97

§117.356. Revision of Final Control Plan. 7-27 (page 210), TXd97

******************************end outline tx7B3d097**********************mx9*****

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DIVISION 3: HOUSTON-GALVESTON-BRAZORIA OZONE NONATTAINMENT AREA MAJOR SOURCES
§§117.300, 117.303, 117.305, 117.310, 117.315, 117.320, 117.323, 117.330, 117.335, 117.340, 117.345, 117.350, 117.352, 117.354, 117.356

STATUTORY AUTHORITY

The new sections are adopted under Texas Water Code, §5.102, concerning General Powers, §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. In addition, the sections are adopted under Texas Health and Safety Code, §382.002, concerning Policy and Purpose, which states the policy and purpose of the State of Texas and the Texas Clean Air Act; §382.011, concerning General Powers and Duties, which provides the commission with the authority to establish the level of quality to be maintained in the state's air and the authority to control the quality of the state's air; §382.012, concerning State Air Control Plan, which requires the commission to develop plans for protection of the state's air; §382.014, concerning Emission Inventory, which authorizes the commission to require submission information relating to emissions of air contaminants; §382.016, concerning Monitoring Requirements; Examination of Records, which authorizes the commission to prescribe requirements for owners or operators of sources to make and maintain records of emissions measurements; §382.017, concerning Rules, which provides the commission the authority to adopt rules consistent with the policy and purposes of the Texas Clean Air Act; §382.021, concerning Sampling Methods and Procedures, which authorizes the commission to prescribe the sampling methods and procedures; and §382.051(d), concerning Permitting Authority of Commission Rules, which authorizes the commission to adopt rules as necessary to comply with changes in federal law or regulations applicable to permits under Chapter 382. In addition, the new sections are adopted under federal mandates contained in 42 United States Code, §§7401 *et seq.*, which require states to adopt pollution control measures in order to reach specific air quality standards in particular areas of the state.

The adopted sections implement Texas Health and Safety Code, §§382.002, 382.011, 382.012, 382.014, 382.016, 382.017, 382.021, and 382.051(d).

§117.300. Applicability.

The provisions of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources) apply to the following units located at any major stationary source of nitrogen oxides located within the Houston-Galveston-Brazoria ozone nonattainment area:

(1) industrial, commercial, or institutional boilers and process heaters;

(2) stationary gas turbines;

(3) stationary internal combustion engines;

(4) fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents);

(5) boilers and industrial furnaces that were regulated as existing facilities in 40 Code of Federal Regulations Part 266, Subpart H (as was in effect on June 9, 1993);

(6) duct burners used in turbine exhaust ducts;

(7) pulping liquor recovery furnaces;

(8) lime kilns;

(9) lightweight aggregate kilns;

(10) heat treating furnaces and reheat furnaces;

(11) magnesium chloride fluidized bed dryers; and

(12) incinerators.

§117.303. Exemptions.

(a) General exemptions. Units exempted from the provisions of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources), except as specified in §§117.310(f), 117.340(j), 117.345(f)(6) and (10), 117.350(c)(1), and 117.354(a)(5) of this title (relating to Emission Specifications for Attainment Demonstration; Continuous Demonstration of Compliance; Notification, Recordkeeping, and Reporting Requirements; Initial Control Plan Procedures; and Final Control Plan Procedures for Attainment Demonstration Emission Specifications), include the following:

(1) any new units placed into service after November 15, 1992, except for new units that are qualified, at the option of the owner or operator, as functionally identical replacement for existing units under §117.305(a)(3) of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). Any emission credits resulting from the operation of such replacement units are limited to the cumulative maximum rated capacity of the units replaced. This exemption no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration specified in §117.9020 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources);

(2) any industrial, commercial, or institutional boiler or process heater with a maximum rated capacity of less than 40 million British thermal units per hour (MMBtu/hr). This exemption no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration specified in §117.9020 of this title;

(3) heat treating furnaces and reheat furnaces. This exemption no longer applies to any heat treating furnace or reheat furnace with a maximum rated capacity of 20 MMBtu/hr or greater after the appropriate compliance date(s) for emission specifications for attainment demonstration specified in §117.9020 of this title;

(4) flares, incinerators, pulping liquor recovery furnaces, sulfur recovery units, sulfuric acid regeneration units, molten sulfur oxidation furnaces, and sulfur plant reaction boilers. This

exemption no longer applies to the following units after the appropriate compliance date(s) for emission specifications for attainment demonstration specified in §117.9020 of this title:

(A) incinerators with a maximum rated capacity of 40 MMBtu/hr or greater;and

(B) pulping liquor recovery furnaces;

(5) dryers, kilns, or ovens used for drying, baking, cooking, calcining, and vitrifying. This exemption no longer applies to the following units after the appropriate compliance date(s) for emission specifications for attainment demonstration specified in §117.9020 of this title:

(A) magnesium chloride fluidized bed dryers; and

(B) lime kilns and lightweight aggregate kilns;

(6) stationary gas turbines and stationary internal combustion engines, that are used as follows:

(A) in research and testing;

(B) for purposes of performance verification and testing;

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

(D) exclusively in emergency situations, except that operation for testing or maintenance purposes is allowed for up to 52 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 October 1, 2001, 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;

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

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

(G) as chemical processing gas turbines;

(7) stationary gas turbines with a megawatt (MW) rating of less than 1.0 MW. This exemption no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration specified in §117.9020 of this title;

(8) stationary internal combustion engines with a horsepower (hp) rating of less than 150 hp. This exemption no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration specified in §117.9020 of this title;

(9) any boiler or process heater with a maximum rated capacity of 2.0 MMBtu/hr or less;

(10) any stationary diesel engine placed into service before October 1, 2001, that:

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

(B) has not been modified, reconstructed, or relocated on or after October 1, 2001. 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; and

(11) any new, modified, reconstructed, or relocated stationary diesel engine placed into service on or after October 1, 2001, that:

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

(B) meets 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 paragraph, 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.

(b) RACT exemptions. Units exempted from the emissions specifications of §117.305 of this title include the following:

(1) any industrial, commercial, or institutional boiler or process heater with a maximum rated capacity less than 100 MMBtu/hr;

(2) any low annual capacity factor boiler, process heater, stationary gas turbine, or stationary internal combustion engine as defined in §117.10 of this title (relating to Definitions);

(3) boilers and industrial furnaces that were regulated as existing facilities by the United States Environmental Protection Agency 40 CFR Part 266, Subpart H, as was in effect on June 9, 1993;

(4) fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents);

(5) duct burners used in turbine exhaust ducts;

(6) any lean-burn, stationary, reciprocating internal combustion engine;

(7) any stationary gas turbine with a MW rating less than 10.0 MW;

(8) any new units placed into service after November 15, 1992, except for new units that were placed into service as functionally identical replacement for existing units subject to the provisions of this division as of June 9, 1993. Any emission credits resulting from the operation of such replacement units are limited to the cumulative maximum rated capacity of the units replaced;

(9) stationary gas turbines and engines, that are demonstrated to operate less than 850 hours per year, based on a rolling 12-month average; and

(10) stationary internal combustion engines with a hp rating of less than 150 hp.

§117.305. Emission Specifications for Reasonably Available Control Technology (RACT).

(a) No person shall allow the discharge of air contaminants into the atmosphere to exceed the emission specifications of this section, except as provided in §§117.315, 117.323, or 117.9800 of this title (relating to Alternative Plant-Wide Emission Specifications; Source Cap; and Use of Emission Credits for Compliance).

(1) For purposes of this subchapter, the lower of any permit nitrogen oxides (NOx) emission limit in effect on June 9, 1993, under a permit issued in accordance with Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) and the emission specifications of subsections (b) - (d) of this section apply, except that:

(A) gas-fired boilers and process heaters operating under a permit issued after March 3, 1982, with a NOx emission limit of 0.12 pounds per million British thermal units (lb/MMBtu) heat input, are limited to that rate for the purposes of this subchapter; and

(B) gas-fired boilers and process heaters that have had NOx reduction projects permitted since November 15, 1990, and prior to June 9, 1993, that were solely for the purpose of making early NOx reductions, are subject to the appropriate emission specification of subsection (b) of this section. The affected person shall document that the NOx reduction project was solely for the purpose of obtaining early reductions, and include this documentation in the initial control plan required in §117.350 of this title (relating to Initial Control Plan Procedures).

(2) For purposes of calculating NOx emission limitations under this section from existing permit limits, the following procedure must be used:

(A) the NOx emission limit explicitly stated in lb/MMBtu of heat input by permit provision (converted from low heating value to high heating value, as necessary); or

(B) the NOx emission limit is the limit calculated as the permit Maximum Allowable Emission Rate Table emission limit in pounds per hour, divided by the maximum heat input to the unit in million British thermal units per hour (MMBtu/hr), as represented in the permit application. In the event the maximum heat input to the unit is not explicitly stated in the permit application, the rate must be calculated from Table 6 of the permit application, using the design maximum fuel flow rate and higher heating value of the fuel, or, if neither of the above are available, the unit's nameplate heat input.

(3) For any unit placed into service after June 9, 1993, and before the final compliance date as specified in §117.9020 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources) as functionally identical replacement for an existing unit or group of units subject to the provisions of this chapter, the higher of any permit NOx emission limit under a permit issued after June 9, 1993, in accordance with Chapter 116 of this title and the emission limits of subsections (b) - (d) of this section applies. Any emission credits resulting from the operation of such replacement units are limited to the cumulative maximum rated capacity of the units replaced. The inclusion of such new units is an optional method for complying with the emission limitations of §117.315 or §117.323 of this title. Compliance with this paragraph does not eliminate the requirement for new units to comply with Chapter 116 of this title.

(b) For each boiler and process heater with a maximum rated capacity greater than or equal to 100.0 MMBtu/hr of heat input, the applicable NOx emission specification is as follows:

(1) gas-fired boilers, as follows:

(A) low heat release boilers with no preheated air or preheated air less than 200 degrees Fahrenheit, 0.10 lb/MMBtu of heat input;

(B) low heat release boilers with preheated air greater than or equal to 200 degrees Fahrenheit and less than 400 degrees Fahrenheit, 0.15 lb/MMBtu of heat input;

(C) low heat release boilers with preheated air greater than or equal to 400 degrees Fahrenheit, 0.20 lb/MMBtu of heat input;

(D) high heat release boilers with no preheated air or preheated air less than 250 degrees Fahrenheit, 0.20 lb/MMBtu of heat input;

(E) high heat release boilers with preheated air greater than or equal to 250 degrees Fahrenheit and less than 500 degrees Fahrenheit, 0.24 lb/MMBtu of heat input; or

(F) high heat release boilers with preheated air greater than or equal to 500 degrees Fahrenheit, 0.28 lb/MMBtu of heat input;

(2) gas-fired process heaters, based on either air preheat temperature or firebox temperature, as follows:

(A) based on air preheat temperature:

(i) process heaters with preheated air less than 200 degrees Fahrenheit, 0.10 lb/MMBtu of heat input;

(ii) process heaters with preheated air greater than or equal to 200 degrees Fahrenheit and less than 400 degrees Fahrenheit, 0.13 lb/MMBtu of heat input; or

(iii) process heaters with preheated air greater than or equal to 400 degrees Fahrenheit, 0.18 lb/MMBtu of heat input; or

(B) based on firebox temperature:

(i) process heaters with a firebox temperature less than 1,400 degrees Fahrenheit, 0.10 lb/MMBtu of heat input;

(ii) process heaters with a firebox temperature greater than or equal to 1,400 degrees Fahrenheit and less than 1,800 degrees Fahrenheit, 0.125 lb/MMBtu of heat input; or

(iii) process heaters with a firebox temperature greater than or equal to 1,800 degrees Fahrenheit, 0.15 lb/MMBtu of heat input;

(3) liquid fuel-fired boilers and process heaters, 0.30 lb/MMBtu of heat input;

(4) wood fuel-fired boilers and process heaters, 0.30 lb/MMBtu of heat input;

(5) any unit operated with a combination of gaseous, liquid, or wood fuel, a variable emission limit calculated as the heat input weighted sum of the applicable emission limits of this subsection;

(6) for any gas-fired boiler or process heater firing gaseous fuel that contains more than 50% hydrogen by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, a multiplier of up to 1.25 times the appropriate emission limit in this subsection may be used for that eight-hour period. The total hydrogen volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of hydrogen in the fuel supply. The multiplier may not be used to increase limits set by permit. The following equation must be used by an owner or operator using a gas-fired boiler or process heater that is subject to this paragraph and one of the rolling 30-day averaging period emission limitations contained in paragraph (1) or (2) of this subsection to calculate an emission limitation for each rolling 30-day period:

Figure: 30 TAC §117.305(b)(6)

$$EL_2 = \frac{(EL_1 \times 1.25 \times T_1) + (EL_1 \times T_2)}{T_1 + T_2}$$

Where:

EL_2 = time-weighted NOx emission limitation for each 30-day period, in lb/MMBtu of heat input;

EL_1 = appropriate NOx emission limitation for gas-fired boilers from §117.305(b)(1)(A) - (F) of this title or gas-fired process heaters from §117.305(b)(2)(A) and (B) of this section, in lb/MMBtu of heat input;

1.25 = factor used as a multiplier times the appropriate emission limitation when firing gaseous fuel that contains more than 50% hydrogen by volume, over an eight-hour period;

T_1 = time in hours when firing gaseous fuel that contains more than 50% hydrogen by volume, over an eight-hour period during each 30-day period. The time period when hydrogen rich fuel is combusted must, at a minimum, be a consecutive eight-hour period to be used in the determination of T_1; and

T_2 = time in hours when firing gaseous fuel or hydrogen rich fuel (for less than eight consecutive hours) during each 30-day period.

(7) for units that operate with a NOx continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) under §117.340 of this title (relating to Continuous Demonstration of Compliance), the emission specifications apply as:

(A) the mass of NOx emitted per unit of energy input (lb/MMBtu), on a rolling 30-day average period; or

(B) the mass of NOx emitted per hour (pounds per hour), on a block one-hour average, calculated as the product of the boiler's or process heater's maximum rated capacity and its applicable specification in lb/MMBtu; and

(8) for units that do not operate with a NOx CEMS or PEMS under §117.340 of this title, the emission specifications apply in pounds per hour, as specified in paragraph (7)(B) of this subsection.

(c) No person shall allow the discharge into the atmosphere from any stationary gas turbine with a megawatt (MW) rating greater than or equal to 10.0 MW, emissions in excess of a block one-hour average concentration of 42 parts per million by volume (ppmv) NO_x and 132 ppmv carbon monoxide (CO) at 15% oxygen (O_2), dry basis. For stationary gas turbines equipped with CEMS or PEMS for CO, the owner or operator may elect to comply with the CO emission specification of this subsection using a 24-hour rolling average.

(d) No person shall allow the discharge into the atmosphere from any gas-fired, rich-burn, stationary, reciprocating internal combustion engine rated 150 horsepower (hp) or greater, NO_x emissions in excess of a block one-hour average of 2.0 grams per horsepower-hour (g/hp-hr) and CO emissions is excess of a block one-hour average of 3.0 g/hp-hr.

(e) No person shall allow the discharge into the atmosphere from any boiler or process heater subject to NO_x emission specifications in subsection (a) or (b) of this section, CO emissions in excess of the following limitations:

(1) for gas or liquid fuel-fired boilers or process heaters, 400 ppmv at 3.0% O_2, dry basis;

(2) for wood fuel-fired boilers or process heaters, 775 ppmv at 7.0% O_2, dry basis; and

(3) for units equipped with CEMS or PEMS for CO, the limits of paragraphs (1) and (2) of this subsection apply on a rolling 24-hour averaging period. For units not equipped with CEMS or PEMS for CO, the specifications apply on a one-hour average.

(f) No person shall allow the discharge into the atmosphere from any unit subject to a NO_x emission specification in this section (including an alternative to the NO_x limit in this section under §117.315 or §117.323 of this title) ammonia emissions in excess of 20 ppmv based on a block one-hour averaging period.

(g) This section no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration given in §117.9020(2) of this title. For purposes of this subsection, this means that the RACT emission specifications of this section remain in effect until the emissions allocation for a unit under the Houston-Galveston-Brazoria mass emissions cap are equal to or less than the allocation that would be calculated using the RACT emission specifications of this section.

§117.310. Emission Specifications for Attainment Demonstration.

(a) Emission specifications for the Mass Emission Cap and Trade Program. The nitrogen oxides (NO_x) emission rate values used to determine allocations for Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) must be the lower of any applicable permit limit in a permit issued before January 2, 2001; any permit issued on or after January 2, 2001, that the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001; any limit in a permit by rule under which construction commenced by January 2, 2001; or the following emission specifications:

(1) gas-fired boilers:

(A) with a maximum rated capacity equal to or greater than 100 million British thermal units per hour (MMBtu/hr), 0.020 pounds per million British thermal units (lb/MMBtu);

(B) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, but less than 100 MMBtu/hr, 0.030 lb/MMBtu; and

(C) with a maximum rated capacity less than 40 MMBtu/hr, 0.036 lb/MMBtu (or alternatively, 30 parts per million by volume (ppmv) NO_x, at 3.0% oxygen (O_2), dry basis);

(2) fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents), one of the following:

(A) 40 ppmv NO_x at 0.0% O_2, dry basis;

(B) a 90% NOx reduction of the exhaust concentration used to calculate the June - August 1997 daily NOx emissions. To ensure that this emission specification will result in a real 90% reduction in actual emissions, a consistent methodology must be used to calculate the 90% reduction; or

(C) alternatively, for units that did not use a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) to determine the June - August 1997 exhaust concentration, the owner or operator may:

(i) install and certify a NOx CEMS or PEMS as specified in §117.340(f) or (g) of this title (relating to Continuous Demonstration of Compliance) no later than June 30, 2001;

(ii) establish the baseline NOx emission level to be the third quarter 2001 data from the CEMS or PEMS;

(iii) provide this baseline data to the executive director no later than October 31, 2001; and

(iv) achieve a 90% NOx reduction of the exhaust concentration established in this baseline;

(3) boilers and industrial furnaces (BIF units) that were regulated as existing facilities in 40 Code of Federal Regulations (CFR) Part 266, Subpart H (as was in effect on June 9, 1993):

(A) with a maximum rated capacity equal to or greater than 100 MMBtu/hr, 0.015 lb/MMBtu; and

(B) with a maximum rated capacity less than 100 MMBtu/hr:

(i) 0.030 lb/MMBtu; or

(ii) an 80% reduction from the emission factor used to calculate the June - August 1997 daily NO_x emissions. To ensure that this emission specification will result in a real 80% reduction in actual emissions, a consistent methodology must be used to calculate the 80% reduction;

(4) coke-fired boilers, 0.057 lb/MMBtu;

(5) wood fuel-fired boilers, 0.060 lb/MMBtu;

(6) rice hull-fired boilers, 0.089 lb/MMBtu;

(7) liquid-fired boilers, 2.0 pounds per 1,000 gallons of liquid burned;

(8) process heaters:

(A) other than pyrolysis reactors:

(i) with a maximum rated capacity equal to or greater than 40 MMBtu/hr, 0.025 lb/MMBtu; and

(ii) with a maximum rated capacity less 40 MMBtu/hr, 0.036 lb/MMBtu (or alternatively, 30 ppmv NO_x, at 3.0% O_2, dry basis); and

(B) pyrolysis reactors, 0.036 lb/MMBtu;

(9) stationary, reciprocating internal combustion engines:

(A) gas-fired rich-burn engines:

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

(ii) all others, 0.50 g/hp-hr;

(B) gas-fired lean-burn engines, except as specified in subparagraph (C) of this paragraph:

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

(ii) all others, 0.50 g/hp-hr;

(C) dual-fuel engines:

(i) with initial start of operation on or before December 31, 2000, 5.83 g/hp-hr; and

(ii) with initial start of operation after December 31, 2000, 0.50 g/hp-hr; and

(D) diesel engines, excluding dual-fuel engines, placed into service before October 1, 2001, that have not been modified, reconstructed, or relocated on or after October 1, 2001, the lower of 11.0 g/hp-hr or the emission rate established by testing, monitoring, manufacturer's guarantee, or manufacturer's other data. 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 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; and

(E) for diesel engines, excluding dual-fuel engines, not subject to subparagraph (D) of this paragraph:

(i) with a horsepower rating of less than 11 horsepower (hp) that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2004, 7.0 g/hp-hr; and

(II) on or after October 1, 2004, 5.0 g/hp-hr;

(ii) with a horsepower rating of 11 hp or greater, but less than 25 hp, that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2004, 6.3 g/hp-hr; and

(II) on or after October 1, 2004, 5.0 g/hp-hr;

(iii) with a horsepower rating of 25 hp or greater, but less than 50 hp, that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2003, 6.3 g/hp-hr; and

(II) on or after October 1, 2003, 5.0 g/hp-hr;

(iv) with a horsepower rating of 50 hp or greater, but less than 100 hp, that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2003, 6.9 g/hp-hr;

(II) on or after October 1, 2003, but before October 1, 2007, 5.0 g/hp-hr; and

(III) on or after October 1, 2007, 3.3 g/hp-hr;

(v) with a horsepower rating of 100 hp or greater, but less than 175 hp, that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2002, 6.9 g/hp-hr;

(II) on or after October 1, 2002, but before October 1, 2006, 4.5 g/hp-hr; and

(III) on or after October 1, 2006, 2.8 g/hp-hr;

(vi) with a horsepower rating of 175 hp or greater, but less than 300 hp, that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2002, 6.9 g/hp-hr;

(II) on or after October 1, 2002, but before October 1, 2005, 4.5 g/hp-hr; and

(III) on or after October 1, 2005, 2.8 g/hp-hr;

(vii) with a horsepower rating of 300 hp or greater, but less than 600 hp, that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2005, 4.5 g/hp-hr; and

(II) on or after October 1, 2005, 2.8 g/hp-hr;

(viii) with a horsepower rating of 600 hp or greater, but less than or equal to 750 hp, that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2005, 4.5 g/hp-hr; and

(II) on or after October 1, 2005, 2.8 g/hp-hr; and

(ix) with a horsepower rating of 750 hp or greater that are installed, modified, reconstructed, or relocated:

(I) on or after October 1, 2001, but before October 1, 2005, 6.9 g/hp-hr; and

(II) on or after October 1, 2005, 4.5 g/hp-hr;

(10) stationary gas turbines:

(A) rated at 10.0 megawatts (MW) or greater, 0.032 lb/MMBtu;

(B) rated at 1.0 MW or greater, but less than 10.0 MW, 0.15 lb/MMBtu; and

(C) rated at less than 1.0 MW, 0.26 lb/MMBtu;

(11) duct burners used in turbine exhaust ducts, the corresponding gas turbine emission specification of paragraph (10) of this subsection;

(12) pulping liquor recovery furnaces, either:

(A) 0.050 lb/MMBtu; or

(B) 1.08 pounds per air-dried ton of pulp;

(13) kilns:

(A) lime kilns, 0.66 pounds per ton of calcium oxide; and

(B) lightweight aggregate kilns, 1.25 pounds per ton of product;

(14) metallurgical furnaces:

(A) heat treating furnaces, 0.087 lb/MMBtu; and

(B) reheat furnaces, 0.062 lb/MMBtu;

(15) magnesium chloride fluidized bed dryers, a 90% reduction from the emission factor used to calculate the 1997 ozone season daily NOx emissions;

(16) incinerators, either of the following:

(A) an 80% reduction from the emission factor used to calculate the June - August 1997 daily NOx emissions. To ensure that this emission specification will result in a real 80% reduction in actual emissions, a consistent methodology must be used to calculate the 80% reduction; or

(B) 0.030 lb/MMBtu; and

(17) as an alternative to the emission specifications in paragraphs (1) - (16) of this subsection for units with an annual capacity factor of 0.0383 or less, 0.060 lb/MMBtu. For units placed into service on or before January 1, 1997, the 1997 - 1999 average annual capacity factor must be used to determine whether the unit is eligible for the emission specification of this paragraph. For units placed into service after January 1, 1997, the annual capacity factor must be calculated from two consecutive years in the first five years of operation to determine whether the unit is eligible for the emission specification of this paragraph, using the same two consecutive years chosen for the activity level baseline. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title (relating to Definitions).

(b) NOx averaging time. The averaging time for the emission specifications of subsection (a) of this section must be as specified in Chapter 101, Subchapter H, Division 3 of this title, except that electric generating facilities (EGFs) must also comply with the daily and 30-day system cap emission limitations of §117.320 of this title (relating to System Cap).

(c) (NOT PART OF SIP REVISION)

(d) Compliance flexibility.

(1) Section 117.325 of this title is not an applicable method of compliance with the NOx emission specifications of this section.

(2) An owner or operator may petition the executive director for an alternative to the CO or ammonia specifications of this section in accordance with §117.325 of this title.

(3) An owner or operator may not use the alternative methods specified in §§117.315, 117.323, and 117.9800 of this title (relating to Alternative Plant-Wide Emission Specifications; Source Cap; and Use of Emission Credits for Compliance) to comply with the NOx emission specifications of this section. The owner or operator shall use the mass emissions cap and trade program in Chapter 101, Subchapter H, Division 3 of this title to comply with the NOx emission specifications of this section, except that electric generating facilities must also comply with the daily and 30-day system cap emission limitations of §117.320 of this title. An owner or operator may use the alternative methods specified in §117.9800 of this title for purposes of complying with §117.320 of this title.

(e) Prohibition of circumvention:

(1) the maximum rated capacity used to determine the applicability of the emission specifications in subsection (a) of this section and the initial control plan, compliance demonstration, monitoring, testing requirements, and final control plan in §§117.335, 117.340, 117.350, and 117.354 of this title (relating to Initial Demonstration of Compliance; Continuous Demonstration of Compliance; Initial Control Plan Procedures; and Final Control Plan Procedures for Attainment Demonstration Emission Specifications) must be:

(A) the greater of the following:

(i) the maximum rated capacity as of December 31, 2000; or

(ii) the maximum rated capacity after December 31, 2000; or

(B) alternatively, the maximum rated capacity authorized by a permit issued under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) on or after January 2, 2001, that the owner or operator submitted an application determined to be administratively complete by the executive director before January 2, 2001, provided that the maximum rated capacity authorized by the permit issued on or after January 2, 2001, is no less than the maximum rated capacity represented in the permit application as of January 2, 2001;

(2) a unit's classification is determined by the most specific classification applicable to the unit as of December 31, 2000. For example, a unit that is classified as a boiler as of December 31, 2000, but subsequently is authorized to operate as a BIF unit, is classified as a boiler for the purposes of this chapter. In another example, a unit that is classified as a stationary gas-fired engine as of December 31, 2000, but subsequently is authorized to operate as a dual-fuel engine, is classified as a stationary gas-fired engine for the purposes of this chapter;

(3) changes after December 31, 2000, to a unit subject to subsection (a) of this section (ESAD unit) that result in increased NO_x emissions from a unit not subject to subsection (a) of this section (non-ESAD unit), such as redirecting one or more fuel or waste streams containing chemical-bound nitrogen to an incinerator with a maximum rated capacity of less than 40 MMBtu/hr or a flare, is only allowed if:

(A) the increase in NO_x emissions at the non-ESAD unit is determined using a CEMS or PEMS that meets the requirements of §117.340(f) or (g) of this title, or through stack testing that meets the requirements of §117.335(e) of this title; and

(B) a deduction in allowances equal to the increase in NOx emissions at the non-ESAD unit is made as specified in §101.354 of this title (relating to Allowance Deductions);

(4) a source that met the definition of major source on December 31, 2000, is always classified as a major source for purposes of this chapter. A source that did not meet the definition of major source (i.e., was a minor source, or did not yet exist) on December 31, 2000, but at any time after December 31, 2000, becomes a major source, is from that time forward always classified as a major source for purposes of this chapter; and

(5) the availability under subsection (a)(17) of this section of an emission specification for units with an annual capacity factor of 0.0383 or less is based on the unit's status on December 31, 2000. Reduced operation after December 31, 2000, cannot be used to qualify for a more lenient emission specification under subsection (a)(17) of this section than would otherwise apply to the unit.

(f) Operating restrictions. No person shall start or operate any stationary diesel or dual-fuel engine for testing or maintenance between the hours of 6:00 a.m. and noon, except:

(1) for specific manufacturer's recommended testing requiring a run of over 18 consecutive hours;

(2) to verify reliability of emergency equipment (e.g., emergency generators or pumps) immediately after unforeseen repairs. Routine maintenance such as an oil change is not considered to be an unforeseen repair; or

(3) firewater pumps for emergency response training conducted in the months of April through October.

§117.315. Alternative Plant-Wide Emission Specifications.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NOx) emission limits of §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) or §117.310 of this title (relating to Emission Specifications for Attainment

Demonstration) by achieving equivalent NO_x emission reductions obtained by compliance with a plant-wide emission specification. Any owner or operator who elects to comply with a plant-wide emission specification shall reduce emissions of NO_x from affected units so that if all such units were operated at their maximum rated capacity, the plant-wide emission rate of NO_x from these units would not exceed the plant-wide emission specification as defined in §117.10 of this title (relating to Definitions).

(b) The owner or operator shall establish an enforceable NO_x emission limit for each affected unit at the source as follows.

(1) For boilers and process heaters that operate with a continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) in accordance with §117.340 of this title (relating to Continuous Demonstration of Compliance), the emission specifications apply in:

(A) the units of the applicable standard (the mass of NO_x emitted per unit of energy input (pounds per million British thermal units (lb/MMBtu) or parts per million by volume (ppmv)), on a rolling 30-day average period; or

(B) as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average.

(2) For boilers and process heaters that do not operate with CEMS or PEMS, the emission specifications apply as the mass of NO_x emitted per hour (pounds per hour), on a block one-hour average.

(3) For stationary gas turbines, the emission specifications apply as the NO_x concentration in ppmv at 15% oxygen (O_2), dry basis on a block one-hour average.

(4) For stationary internal combustion engines, the NO_x emission specifications apply in units of grams per horsepower-hour (g/hp-hr) on a block one-hour average.

(c) An owner or operator of any gaseous and liquid fuel-fired unit that derives more than 50% of its annual heat input from gaseous fuel shall use only the appropriate gaseous fuel emission limit of

§117.305 or §117.310 of this title at maximum rated capacity in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NOx emission rate while firing gas, calculated in accordance with subsection (a) of this section. The owner or operator shall also:

(1) comply with the assigned maximum allowable emission rate while firing gas only;

(2) comply with the liquid fuel emission limit of §117.305 of this title while firing liquid fuel only; and

(3) comply with a limit calculated as the actual heat input weighted sum of the assigned gas-firing allowable emission rate and the liquid fuel emission limit of §117.305 of this title while operating on liquid and gaseous fuel concurrently.

(d) An owner or operator of any gaseous and liquid fuel-fired unit that derives more than 50% of its annual heat input from liquid fuel shall use a heat input weighted sum of the appropriate gaseous and liquid fuel emission specifications of §117.305 or §117.310 of this title in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NOx emission rate, calculated in accordance with subsection (a) of this section.

(e) An owner or operator of any unit operated with a combination of gaseous (or liquid) and solid fuels shall use a heat input weighted sum of the appropriate emission specifications of §117.305 of this title in calculating the plant-wide emission specification and shall assign to the unit the maximum allowable NOx emission rate, calculated in accordance with subsection (a) of this section.

(f) Units exempted from emission specifications in accordance with §117.303(b) of this title (relating to Exemptions) are also exempt under this section and must not be included in the plant-wide emission specification, except as follows. The owner or operator of exempted units as defined in §117.303(b) of this title may opt to include one or more of an entire equipment class of exempted units into the alternative plant-wide emission specifications.

(1) Low annual capacity factor boilers, process heaters, stationary gas turbines, or stationary internal combustion engines as defined in §117.10 of this title are not to be considered as part of the opt-in class of equipment.

(2) The ammonia and carbon monoxide (CO) emission specifications of §117.305 or §117.310 of this title apply to the opt-in units.

(3) The individual NO_x emission limit that is to be used in calculating the alternative plant-wide emission specifications is the lowest of any applicable permit emission specification determined in accordance with §117.305(a) of this title or the specification of paragraph (4) of this subsection.

(4) The equipment classes that may be included in the alternative plant-wide emission specifications and the NO_x emission rates that are to be used in calculating the alternative plant-wide emission specifications are listed in the table titled §117.315(f) OPT-IN UNITS.

Figure: 30 TAC §117.315(f)(4)

§117.315(f) OPT-IN UNITS

Equipment Class/Description	**Emission Specification**
fluid catalytic cracking unit CO boilers	50% NO_x reduction across the inlet of the CO boiler to the outlet of the CO boiler, with the outlet concentration in ppmv converted into lb/MMBtu of heat input
lean-burn, gas-fired, stationary, reciprocating internal combustion engines rated 150 horsepower (hp) or greater	5.0 g/hp-hr of NO_x under all operating conditions
boilers or process heaters with a maximum rated capacity (MRC): 40 million British thermal units per hour (MMBtu/hr) $\leq$ MRC $<$ 100 MMBtu/hr	the emission specifications in §117.305(a) of this title for the applicable type of unit
stationary gas turbines with a megawatt (MW) rating: 1.0 MW $\leq$ MW rating $<$ 10.0 MW	42 ppmv NO_x at 15% O_2, dry basis

boilers and industrial furnaces that are regulated as existing facilities by 40 Code of Federal Regulations Part 266, Subpart H	the appropriate emission limitation in §117.305(b) of this title

(g) Solely for the purposes of calculating the plant-wide emission specification, the allowable NO_x emission rate (in pounds per hour) for each affected unit must be calculated from the emission specifications of §117.305 of this title, as follows.

(1) For each affected boiler and process heater, the rate is determined by the following equation.

Figure: 30 TAC §117.315(g)(1)

$$EL_{PW} = MRC \times ES$$

Where:

EL_{PW} = plant-wide emission specification in pounds per hour;

ES = emission specification in lb/MMBtu; and

MRC = maximum rated capacity in million British thermal units per hour.

(2) For each affected stationary internal combustion engine, the rate is determined by the following equation.

Figure: 30 TAC §117.315(g)(2)

$$EL_{PW} = \frac{MRC \times ES}{HR \times (454 \times 10^6)}$$

Where:

EL_{PW} = plant-wide emission specification in pounds per hour;

ES = emission specification in g/hp-hr;

MRC = engine manufacturer's rated heat input in million British thermal units per hour; and

HR = engine manufacturer's rated heat rate at the engines horsepower rating, in British thermal units per horsepower-hour.

(3) For each affected stationary gas turbine, the rate is determined by the following equations.

Figure: 30 TAC §117.315(g)(3)

$$C_{instack} = A_{NO_X} \times \left(1 - \frac{\%H_2O}{100}\right) \times \left[\left(20.9 - \frac{\%O_2}{\left(1 - \frac{\%H_2O}{100}\right)}\right) \times \frac{1}{5.9}\right]$$

$$\mathrm{EL}_{\mathrm{PW}} = C_{instack} \times MF \times \left(\frac{46}{28} \times 10^{-6}\right)$$

Where:

$C_{instack}$ = the NOx in-stack concentration in ppmv;

A_{NOX} = the applicable NOx emission specification of §117.305(c) of this title (expressed in ppmv NOx at 15% O_2, dry basis);

$\%H_2O$ = the volume percent of water in the stack gases, as calculated from the manufacturer's data, or other data as approved by the executive director, at megawatt (MW) rating and International Standards Organization (ISO) flow conditions;

$\%O_2$ = the volume percent of O_2 in the stack gases on a wet basis, as calculated from the manufacturer's data or other data as approved by the executive director, at MW rating and ISO conditions;

EL_{PW} = plant-wide emission specification in pounds per hour; and

MF = the turbine manufacturer's rated exhaust flow rate, in pounds per hour at MW rating and ISO flow conditions.

(4) Each affected gas-fired boiler and process heater firing gaseous fuel that contains more than 50% hydrogen (H_2) by volume, on an annual basis, may be adjusted with a multiplier of up to 1.25 times the product of its maximum rated capacity and its NO_x emission specification of §117.305 of this title.

(A) Double application of the H_2 content multiplier using this paragraph and §117.305(b)(6) of this title is not allowed.

(B) The multiplier may not be used to increase a limit set by permit.

(C) The fuel gas composition must be sampled and analyzed every three hours.

(D) This paragraph is not applicable for establishing compliance with §117.310 of this title.

(h) The owner or operator of any gas-fired boiler or process heater firing gaseous fuel that contains more than 50% H_2 by volume, over an eight-hour period, in which the fuel gas composition is sampled and analyzed every three hours, may use a multiplier of up to 1.25 times the emission limit assigned to the unit in this section for that eight-hour period. The total H_2 volume in all gaseous fuel streams will be divided by the total gaseous fuel flow volume to determine the volume percent of H_2 in the fuel supply. This subsection is not applicable to:

(1) units under subsection (g)(4) of this section;

(2) increase limits set by permit; or

(3) establish compliance with §117.310 of this title.

(i) This section no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration given in §117.9020(2) of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources). For purposes of this subsection, this means that the alternative plant-wide emission specifications of this section remain in effect until the emissions allocation for units under the Houston-Galveston-Brazoria mass emissions cap are equal to or less than the allocation that would be calculated using the alternative plant-wide emission specifications of this section.

§117.320. System Cap.

(a) The owner or operator of any electric generating facility (EGF) shall comply with a daily and 30-day system cap emission limitation for nitrogen oxides (NO_x) in accordance with the requirements of this section. Each EGF in the system cap must be subject to the daily cap and appropriate 30-day cap of this section at all times. An EGF is not subject to this section if electric output is entirely dedicated to industrial customers. "Entirely dedicated" may include up to two weeks per year of service to the electric grid when the industrial customers' load sources are not operating. Alternatively, an EGF that generates electricity primarily for internal use, but that during 1997 and all subsequent calendar years transferred (or will transfer) that generated electricity to a utility power distribution system at a rate less than 3.85% of its actual electrical generation is not subject to the requirements of this section.

(b) Each EGF that is subject to §117.310 of this title (relating to Emission Specifications for Attainment Demonstration) must be included in the system cap.

(c) The system cap must be calculated as follows.

(1) A rolling 30-day average emission cap applicable during the months of July, August, and September must be calculated using the following equation.

Figure: 30 TAC §117.320(c)(1)

$$Cap_{30day} = \sum_{i=1}^{N} \left(H_i \times R_i\right)$$

Where:

Cap_{30day} = the NO_x 30-day rolling average emission cap in pounds per day;

i	=	each EGF in the electric power generating system;
N	=	the total number of EGFs in the emission cap;
H_i	=	(A) the average of the daily heat input for each EGF in the emission cap, in million British thermal units per day (MMBtu per day), as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1997, 1998, and 1999;

(B) for an EGF exempt from the 40 Code of Federal Regulations (CFR) Part 75 monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for an EGF in the system subject to 40 CFR Part 75 monitoring) is not available, the daily average of the highest calendar month heat input in 1997 - 1999 may be used;

(C) the level of activity authorized by the executive director for the third quarter (July, August, and September), until such time two consecutive third quarters of actual level of activity data are available after the end of the adjustment period as defined in §101.350 of this title (relating to Definitions), must be used for the following:

(i) an EGF that the owner or operator has submitted, under Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification), an application determined to be administratively complete by the executive director before January 2, 2001;

(ii) an EGF that qualifies for a permit by rule under Chapter 106 of this title (relating to Permits by Rule) and have commenced construction before January 2, 2001; and

(iii) an EGF that was not in operation before January 1, 1997;

(D) after two consecutive third quarters of actual level of activity data are available for an EGF described in subsection (c)(1) of this section, variable (C) of this figure, the owner or operator may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title; and

(E) in extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period described in subsection (c)(1) of this section, variable (A) - (D) of this figure. Applications seeking an alternate baseline period must be submitted by the owner or operator of the EGF to the executive director:

(i) no later than December 31, 2001; or

(ii) for an EGF that the baseline period as described in subsection (c)(1) of this section, variable (A) - (D) of this figure is not complete by December 31, 2001, no later than 90 days after completion of the baseline period; and

R_i = the emission specification of §117.310(a) of this title.

(2) A rolling 30-day average emission cap applicable during all months other than July, August, and September must be calculated using the following equation.

Figure: 30 TAC §117.320(c)(2)

$$Cap_{30day} = \sum_{i=1}^{N} (H_i \times R_i)$$

Where:

Cap_{30day} = the NOx 30-day rolling average emission cap in pounds per day;

i = each EGF in the electric power generating system;

N = the total number of EGFs in the emission cap;

H_i = (A) the average of the daily heat input for each EGF in the emission cap, in million British thermal units per day (MMBtu per day), as certified to the executive director, for the system highest 30-day period in the nine months of July, August, and September 1997, 1998, and 1999. For an EGF that the system highest 30-day period in 1997 - 1999 occurs in months other than July - September, the owner or operator may substitute the system highest 30-day period in the nine months comprising the highest three consecutive months in each year of the 1997 - 1999 period;

(B) for an EGF exempt from the 40 CFR Part 75 monitoring requirements, if the heat input data corresponding to the system highest 30-day period (as determined for an EGF in the system subject to 40 CFR Part 75 monitoring) is not available, the daily average of the highest calendar month heat input in 1997 - 1999 may be used;

(C) the level of activity authorized by the executive director for the third quarter (July, August, and September), until such time two consecutive third quarters of actual level of activity data are available after the end of the adjustment period as defined in §101.350 of this title, must be used for the following:

(i) an EGF that the owner or operator has submitted, under Chapter 116 of this title, an application determined to be administratively complete by the executive director before January 2, 2001;

(ii) an EGF that qualifies for a permit by rule under Chapter 106 of this title and commenced construction before January 2, 2001; and

(iii) an EGF that was not in operation before January 1, 1997;

(D) after two consecutive third quarters of actual level of activity data are available for an EGF described in subsection (c)(1) of this section, variable (C) of this figure, the owner or operator may calculate the baseline as the average of any two consecutive third quarters in the first five years of operation. For an EGF that the system highest 30-day period in the first two years of operation occurs in months other than July - September, the owner or operator may substitute the system highest 30-day period in the six months comprising the highest three consecutive months in any two consecutive years in the first five years of operation. The five-year period begins at the end of the adjustment period as defined in §101.350 of this title; and

(E) in extenuating circumstances, the owner or operator of an EGF may request, subject to approval of the executive director, up to two additional calendar years to establish the baseline period described in subsection (c)(1) of this section, variable (A) - (D) of this figure. Applications seeking an alternate baseline period must be submitted by the owner or operator of the EGF to the executive director:

(i) no later than December 31, 2001; or

(ii) for an EGF that the baseline period as described in subsection (c)(1) of this section, variable (A) - (D) of this figure is not complete by December 31, 2001, no later than 90 days after completion of the baseline period; and

R_i = the emission specification of §117.310(a) of this title.

(3) A maximum daily cap must be calculated using the following equation.

Figure: 30 TAC §117.320(c)(3)

$$Cap_{daily} = \sum_{i=1}^{N} (H_{mi} \times R_i)$$

Where:

Cap_{daily}	=	the NO_x maximum daily cap in pounds per day;
i	=	as defined in paragraph (1) of this subsection;
N	=	as defined in paragraph (1) of this subsection;
H_{mi}	=	the maximum heat input, as certified to the executive director, allowed or possible (whichever is lower) in a day; and
R_i	=	as defined in paragraph (1) of this subsection.

(d) The NO_x emissions monitoring required by §117.340 of this title (relating to Continuous Demonstration of Compliance) for each EGF in the system cap must be used to demonstrate continuous compliance with the system cap.

(e) For each operating EGF, the owner or operator shall use one of the following methods to provide substitute emissions compliance data during periods when the NO_x monitor is off-line:

(1) if the NO_x monitor is a continuous emissions monitoring system (CEMS):

(A) subject to 40 Code of Federal Regulations (CFR) 75, use the missing data procedures specified in 40 CFR 75, Subpart D (Missing Data Substitution Procedures); or

(B) subject to 40 CFR 75, Appendix E, use the missing data procedures specified in 40 CFR 75, Appendix E, §2.5 (Missing Data Procedures);

(2) use Appendix E monitoring in accordance with §117.1240(e) of this title (relating to Continuous Demonstration of Compliance);

(3) if the NO_x monitor is a predictive emissions monitoring system (PEMS):

(A) use the methods specified in 40 CFR 75, Subpart D; or

(B) use calculations in accordance with §117.8110(b) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources); or

(4) use the maximum block one-hour emission rate as measured by the 30-day testing.

(f) The owner or operator of any EGF subject to a system cap shall maintain daily records indicating the NOx emissions and fuel usage from each EGF and summations of total NOx emissions and fuel usage for all EGFs under the system cap on a daily basis. Records must also be retained in accordance with §117.345 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(g) The owner or operator of any EGF subject to a system cap shall report any exceedance of the system cap emission limit within 48 hours to the appropriate regional office. The owner or operator shall then follow up within 21 days of the exceedance with a written report to the regional office that includes an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance. Additionally, the owner or operator shall submit semiannual reports for the monitoring systems in accordance with §117.345 of this title.

(h) The owner or operator of any EGF subject to a system cap shall demonstrate initial compliance with the system cap in accordance with the schedule specified in §117.9020 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

(i) An EGF that is permanently retired or decommissioned and rendered inoperable may be included in the system cap emission limit, provided that the permanent shutdown occurred after January 1, 2000. The system cap emission limit is calculated in accordance with subsection (b) of this section.

(j) Emission reductions from shutdowns or curtailments that have been used for netting or offset purposes under the requirements of Chapter 116 of this title (relating to Control of Air Pollution by

Permits for New Construction or Modification) may not be included in the baseline for establishing the cap.

(k) For the purposes of determining compliance with the system cap emission limit, the contribution of each affected EGF that is operating during a startup, shutdown, or emissions event as defined in §101.1 of this title (relating to Definitions) must be calculated from the NOx emission rate measured by the NOx monitor, if operating properly. If the NOx monitor is not operating properly, the substitute data procedures identified in subsection (e) of this section must be used. If neither the NOx monitor nor the substitute data procedure are operating properly, the owner or operator shall use the maximum daily rate measured during the initial demonstration of compliance, unless the owner or operator provides data demonstrating to the satisfaction of the executive director and the United States Environmental Protection Agency that actual emissions were less than maximum emissions during such periods.

§117.323. Source Cap.

(a) An owner or operator may achieve compliance with the nitrogen oxides (NOx) emission limits of §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) by achieving equivalent NOx emission reductions obtained by compliance with a source cap emission limitation in accordance with the requirements of this section. Each equipment category at a source whose individual emission units would otherwise be subject to the NOx emission limits of §117.305 of this title may be included in the source cap. Any equipment category included in the source cap must include all emission units belonging to that category. Equipment categories include, but are not limited to, the following: steam generation, electrical generation, and units with the same product outputs, such as ethylene cracking furnaces. All emission units not included in the source cap must comply with the requirements of §117.305 or §117.315 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT) and Alternative Plant-Wide Emission Specifications).

(b) The source cap allowable mass emission rate must be calculated as follows.

(1) A rolling 30-day average emission cap must be calculated for all emission units included in the source cap using the following equation.

Figure: 30 TAC §117.323(b)(1)

$$Cap_{30day} = \sum_{i=1}^{N} \left(H_i \times R_i \right)$$

Where:

Cap_{30day}	=	the NOx 30-day rolling average emission cap in pounds per day;
i	=	each emission unit in the emission cap;
N	=	the total number of emission units in the emission cap;
H_i	=	for compliance with §117.305(a) - (d) of this title. The actual historical average of the daily heat input for each unit included in the source cap, in million British thermal units per day (MMBtu per day), as certified to the executive director, for a 24 consecutive month period between January 1, 1990, and June 9, 1993, plus one standard deviation of the average daily heat input for that period. All sources included in the source cap must use the same 24 consecutive month period. If sufficient historical data are not available for this calculation, the executive director may approve another method for calculating H_i; and
R_i	=	for compliance with §117.305(a) - (d) of this title:

(i) for emission units subject to the federal New Source Review requirements of 40 Code of Federal Regulations (CFR) §§51.165(a), 51.166, or 52.21, or to the requirements of Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification) that implement these federal requirements, or emission units that have been subject to a New Source Performance Standard requirement of 40 CFR Part 60 prior to June 9, 1993, R_i is the lowest of the actual emission rate or all applicable federally enforceable emission limitations as of June 9, 1993, in pounds per million British thermal units (lb/MMBtu), that apply to emission unit i in the absence of trading. All calculations of emission rates must presume that emission controls in effect on June 9, 1993, are in effect for the two-year period used in calculating the actual heat input; and

(ii) for all other emission units, R_i is the lowest of the reasonably available control technology (RACT) limit of §117.305(b) - (d) or §117.315(f) of this title or the best available control technology NOx limit for any unit subject to a permit issued in accordance with Chapter

116 of this title, in lb/MMBtu, that applies to emission unit i in the absence of trading.

(2) A maximum daily cap must be calculated for all emission units included in the source cap using the following equation.

Figure: 30 TAC §117.323(b)(2)

$$Cap_{daily} = \sum_{i=1}^{N} (H_{mi} \times R_i)$$

Where:

Cap_{daily}	=	the NOx maximum daily cap in pounds per day;
i	=	as defined in paragraph (1) of this subsection;
N	=	as defined in paragraph (1) of this subsection;
H_{mi}	=	the maximum daily heat input, as certified to the executive director, allowed or possible (whichever is lower) in a 24-hour period; and
R_i	=	as defined in paragraph (1) of this subsection.

(3) Each emission unit included in the source cap must be subject to the requirements of both paragraphs (1) and (2) of this subsection at all times.

(4) The owner or operator at its option may include any of the entire classes of exempted units listed in §117.315(f) of this title in a source cap. For compliance with §117.305(a) - (d) of this title, such units are required to reduce emissions available for use in the cap by an additional amount calculated in accordance with the United States Environmental Protection Agency's proposed Economic Incentive Program rules for offset ratios for trades between RACT and non-RACT sources, as published in the February 23, 1993, *Federal Register* (58 FR 11110).

(5) For stationary internal combustion engines, the source cap allowable emission rate must be calculated in pounds per hour using the procedures specified in §117.315(g)(2) of this title.

(6) For stationary gas turbines, the source cap allowable emission rate must be calculated in pounds per hour using the procedures specified in §117.315(g)(3) of this title.

(c) The owner or operator who elects to comply with this section shall:

(1) for each unit included in the source cap, either:

(A) install, calibrate, maintain, and operate a continuous exhaust NOx monitor, carbon monoxide (CO) monitor, an oxygen (O_2) (or carbon dioxide (CO_2)) diluent monitor, and a totalizing fuel flow meter in accordance with the requirements of §117.340 of this title (relating to Continuous Demonstration of Compliance). The required continuous emissions monitoring systems (CEMS) and fuel flow meters must be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel use for each affected unit and must be used to demonstrate continuous compliance with the source cap;

(B) install, calibrate, maintain, and operate a predictive emissions monitoring system (PEMS) and a totalizing fuel flow meter in accordance with the requirements of §117.340 of this title. The required PEMS and fuel flow meters must be used to measure NO_x, CO, and O_2 (or CO_2) emissions and fuel flow for each affected unit and must be used to demonstrate continuous compliance with the source cap; or

(C) for units not subject to continuous monitoring requirements and units belonging to the equipment classes listed in §117.315(f) of this title, the owner or operator may use the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.335(e) of this title (relating to Initial Demonstration of Compliance) in lieu of CEMS or PEMS. Emission rates for these units are limited to the maximum emission rates obtained from testing conducted under §117.335(e) of this title; and

(2) for each operating unit equipped with CEMS, the owner or operator shall either use a PEMS in accordance with §117.340 of this title, or the maximum emission rate as measured by hourly emission rate testing conducted in accordance with §117.335(e) of this title, to provide emissions compliance data during periods when the CEMS is off-line. The methods specified in 40 CFR §75.46 must be used to provide emissions substitution data for units equipped with PEMS.

(d) The owner or operator of any units subject to a source cap shall maintain daily records indicating the NOx emissions from each source and the total fuel usage for each unit and include a total NOx emissions summation and total fuel usage for all units under the source cap on a daily basis. Records must also be retained in accordance with §117.345 of this title (relating to Notification, Recordkeeping, and Reporting Requirements).

(e) The owner or operator of any units operating under this provision shall report any exceedance of the source cap emission limit within 48 hours to the appropriate regional office. The owner or operator shall then follow up within 21 days of the exceedance with a written report that includes an analysis of the cause for the exceedance with appropriate data to demonstrate the amount of emissions in excess of the applicable limit and the necessary corrective actions taken by the company to assure future compliance. Additionally, the owner or operator shall submit semiannual reports for the monitoring systems in accordance with §117.345 of this title.

(f) The owner or operator shall demonstrate initial compliance with the source cap in accordance with the schedule specified in §117.9020(1) of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

(g) For compliance with §117.305(a) - (d) of this title by November 15, 1999, a unit that has operated since November 15, 1990, and has since been permanently retired or decommissioned and rendered inoperable prior to June 9, 1993, may be included in the source cap emission limit under the following conditions.

(1) The unit must have actually operated since November 15, 1990.

(2) For purposes of calculating the source cap emission limit, the applicable emission limit for retired units must be calculated in accordance with subsection (b) of this section.

(3) The actual heat input must be calculated according to subsection (b)(1) of this section. If the unit was not in service 24 consecutive months between January 1, 1990, and June 9, 1993, the actual heat input must be the average daily heat input for the continuous time period that the

unit was in service, plus one standard deviation of the average daily heat input for that period. The maximum heat input must be the maximum heat input, as certified to the executive director, allowed or possible (whichever is lower) in a 24-hour period.

(4) The owner or operator shall certify the unit's operational level and maximum rated capacity.

(5) Emission reductions from shutdowns or curtailments that have not been used for netting or offset purposes under the requirements of Chapter 116 of this title or have not resulted from any other state or federal requirement may be included in the baseline for establishing the cap.

(h) A unit that has been shut down and rendered inoperable after June 9, 1993, but not permanently retired, should be identified in the initial control plan and may be included in the source cap to comply with the NOx emission specifications of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources) required by November 15, 1999.

(i) An owner or operator who chooses to use the source cap option shall include in the initial control plan, if required to be filed under §117.350 of this title (relating to Initial Control Plan Procedures), a plan for initial compliance. The owner or operator shall include in the initial control plan the identification of the election to use the source cap procedure as specified in this section to achieve compliance with this section and shall specifically identify all sources that will be included in the source cap. The owner or operator shall also include in the initial control plan the method of calculating the actual heat input for each unit included in the source cap, as specified in subsection (b)(1) of this section. An owner or operator who chooses to use the source cap option shall include in the final control plan procedures of §117.352 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology) the information necessary under this section to demonstrate initial compliance with the source cap.

(j) For the purposes of determining compliance with the source cap emission limit, the contribution of each affected unit that is operating during a startup, shutdown, or emissions event as defined in §101.1 of this title (relating to Definitions) must be calculated from the NOx emission rate, as measured by the initial demonstration of compliance, for that unit, unless the owner or operator provides data demonstrating to the satisfaction of the executive director that actual emissions were less than maximum emissions during such periods.

(k) This section no longer applies after the appropriate compliance date(s) for emission specifications for attainment demonstration given in §117.9020(2) of this title. For purposes of this paragraph, this means that the source cap of this section remains in effect until the emissions allocation for units under the Houston-Galveston-Brazoria mass emissions cap are equal to or less than the allocation that would be calculated using the source cap of this section.

§117.330. Operating Requirements.

(a) The owner or operator shall operate any unit subject to the emission specifications of §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)) in compliance with those limitations.

(b) The owner or operator shall operate any unit subject to the plant-wide emission specification of §117.315 of this title (relating to Alternative Plant-Wide Emission Specifications) such that the assigned maximum nitrogen oxides (NO_x) emission rate for each unit expressed in units of the applicable emission limit and averaging period, is in accordance with the list approved by the executive director pursuant to §117.352 of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

(c) The owner or operator shall operate any unit subject to the source cap emission limits of §117.323 of this title (relating to Source Cap) in compliance with those limitations.

(d) All units subject to the emission limitations of §§117.305, 117.315, or 117.323 of this title must be operated so as to minimize NO_x emissions, consistent with the emission control techniques selected, over the unit's operating or load range during normal operations. Such operational requirements include the following.

(1) Each boiler, except for wood-fired boilers, must be operated with oxygen (O_2), carbon monoxide (CO), or fuel trim.

(2) Each boiler and process heater controlled with forced flue gas recirculation (FGR) to reduce NO_x emissions must be operated such that the proportional design rate of FGR is maintained, consistent with combustion stability, over the operating range.

(3) Each boiler and process heater controlled with induced draft FGR to reduce NO_x emissions must be operated such that the operation of FGR over the operating range is not restricted by artificial means.

(4) Each unit controlled with steam or water injection must be operated such that injection rates are maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity (corrected to 15% O_2 on a dry basis for stationary gas turbines).

(5) Each unit controlled with post-combustion control techniques must be operated such that the reducing agent injection rate is maintained to limit NO_x concentrations to less than or equal to the NO_x concentrations achieved at maximum rated capacity.

(6) Each stationary internal combustion engine controlled with nonselective catalytic reduction must be equipped with an automatic air-fuel ratio (AFR) controller that operates on exhaust O_2 or CO control and maintains AFR in the range required to meet the engine's applicable emission limits.

(7) Each stationary internal combustion engine must be checked for proper operation of the engine according to §117.8140(b) of this title (relating to Emission Monitoring for Engines).

§117.335. Initial Demonstration of Compliance.

(a) The owner or operator of any unit subject to §117.305 or §117.310 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); and Emission Specifications for Attainment Demonstration) shall test the unit as follows.

(1) The unit must be tested for nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen emissions while firing gaseous fuel or, as applicable:

(A) hydrogen (H_2) fuel for units that may fire more than 50% H_2 by volume; and

(B) liquid and solid fuel.

(2) Units that inject urea or ammonia into the exhaust stream for NOx control must be tested for ammonia emissions.

(3) All units must be tested that belong to equipment classes elected to be included in:

(A) the alternative plant-wide emission specifications as defined in §117.315(f) of this title (relating to Alternative Plant-Wide Emission Specifications); or

(B) the source cap as defined in §117.323(b)(4) of this title (relating to Source Cap).

(4) Initial demonstration of compliance testing must be performed in accordance with the schedule specified in §117.9020 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

(b) The initial demonstration of compliance tests required by subsection (a) of this section must use the methods referenced in subsection (e) or (f) of this section and must be used for determination of initial compliance with the requirements of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources). Test results must be reported in the units of the applicable emission specification and averaging periods.

(c) Any continuous emissions monitoring system (CEMS) or any predictive emissions monitoring system (PEMS) required by §117.340 of this title (relating to Continuous Demonstration of Compliance) must be installed and operational before conducting testing under subsection (a) of this section. Verification of operational status must, as a minimum, include completion of the initial relative accuracy test audit and the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device or system.

(d) Early testing conducted before March 21, 1999, may be used to demonstrate compliance with the requirements of this division, if the owner or operator of an affected facility demonstrates to the executive director that the prior compliance testing at least meets the requirements of subsections (a), (b), (c), (e), and (f) of this section. For early testing, the compliance stack test report required by subsection (g) must be as complete as necessary to demonstrate to the executive director that the stack test was valid and the source has complied with the rule. The executive director reserves the right to request compliance testing or CEMS or PEMS performance evaluation at any time.

(e) Compliance with the requirements of this division for units operating without CEMS or PEMS must be demonstrated according to the requirements of §117.8000 of this title (relating to Stack Testing Requirements).

(f) Initial compliance with the requirements of this division for units operating with CEMS or PEMS in accordance with §117.340 of this title, must be demonstrated after monitor certification testing using the CEMS or PEMS as follows.

(1) For boilers and process heaters complying with a NO_x emission specification in pounds per million British thermal units on a rolling 30-day average, NO_x emissions from the unit are monitored for 30 successive unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission specification. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) For units complying with a NO_x emission specification on a block one-hour average, any one-hour period while operating at the maximum rated capacity, or as near thereto as practicable is used to determine compliance with the NO_x emission specification.

(3) For units complying with a CO emission specification, on a rolling 24-hour average, any 24-hour period is used to determine compliance with the CO emission specification.

(4) For units complying with §117.323 of this title, a rolling 30-day average of total daily pounds of NOx emissions from the units are monitored (or calculated in accordance with §117.323(c) of this title) for 30 successive source operating days and the 30-day average emission rate is used to determine compliance with the NOx emission specification. The 30-day average emission rate is calculated as the average of all daily emissions data recorded by the monitoring and recording system during the 30-day test period. There must be no exceedances of the maximum daily cap during the 30-day test period.

(g) Compliance stack test reports must include the information required in §117.8010 of this title (relating to Compliance Stack Test Reports).

§117.340. Continuous Demonstration of Compliance.

(a) Totalizing fuel flow meters. The owner or operator of units listed in this subsection shall install, calibrate, maintain, and operate a totalizing fuel flow meter, with an accuracy of $\pm$ 5%, to individually and continuously measure the gas and liquid fuel usage. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The owner or operator of units with totalizing fuel flow meters installed prior to March 31, 2005, that do not meet the accuracy requirements of this subsection shall either recertify or replace existing meters to meet the $\pm$ 5% accuracy required as soon as practicable but no later than March 31, 2007. For the purpose of compliance with this subsection for units having pilot fuel supplied by a separate fuel system or from an unmonitored portion of the same fuel system, the fuel flow to pilots may be calculated using the manufacturer's design flow rates rather than measured with a fuel flow meter. The calculated pilot fuel flow rate must be added to the monitored fuel flow when fuel flow is totaled.

(1) The units are the following:

(A) for units that are subject to §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), for stationary gas turbines that are exempt under §117.303(b)(7) of this title (relating to Exemptions):

(i) if individually rated more than 40 million British thermal units per hour (MMBtu/hr):

(I) boilers;

(II) process heaters;

(III) boilers and industrial furnaces that were regulated as existing facilities by 40 Code of Federal Regulations (CFR) Part 266, Subpart H, as was in effect on June 9, 1993; and

(IV) gas turbine supplemental-fired waste heat recovery units;

(ii) stationary, reciprocating internal combustion engines not exempt by §117.303(a)(6), (a)(8), (b)(9), or (b)(10) of this title;

(iii) stationary gas turbines with a megawatt (MW) rating greater than or equal to 1.0 MW operated more than 850 hours per year; and

(iv) fluid catalytic cracking unit boilers using supplemental fuel; and

(B) for units subject to §117.310 of this title (relating to Emission Specifications for Attainment Demonstration):

(i) boilers (excluding wood-fired boilers that must comply by maintaining records of fuel usage as required in §117.345(f) of this title (relating to Notification, Recordkeeping, and Reporting Requirements) or monitoring in accordance with paragraph (2)(A) of this subsection);

(ii) process heaters;

(iii) boilers and industrial furnaces that were regulated as existing facilities by 40 CFR Part 266, Subpart H, as was in effect on June 9, 1993;

(iv) duct burners used in turbine exhaust ducts;

(v) stationary, reciprocating internal combustion engines;

(vi) stationary gas turbines;

(vii) fluid catalytic cracking unit boilers and furnaces using supplemental fuel;

(viii) lime kilns;

(ix) lightweight aggregate kilns;

(x) heat treating furnaces;

(xi) reheat furnaces;

(xii) magnesium chloride fluidized bed dryers; and

(xiii) incinerators (excluding vapor streams resulting from vessel cleaning routed to an incinerator, provided that fuel usage is quantified using good engineering practices, including calculation methods in general use and accepted in new source review permitting in Texas. All other fuel and vapor streams must be monitored in accordance with this subsection.)

(2) The following are alternatives to the fuel flow monitoring requirements of paragraph (1) of this subsection.

(A) Units operating with a nitrogen oxides (NO_x) and diluent continuous emissions monitoring system (CEMS) under subsection (f) of this section may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

(B) Units that vent to a common stack with a NO_x and diluent CEMS under subsection (f) of this section may use a single totalizing fuel flow meter.

(C) Diesel engines operating with run time meters may meet the fuel flow monitoring requirements of this subsection through monthly fuel use records maintained for each engine.

(b) Oxygen (O_2) monitors.

(1) The owner or operator shall install, calibrate, maintain, and operate an O_2 monitor to measure exhaust O_2 concentration on the following units operated with an annual heat input greater than $2.2(10^{11})$ British thermal units per year (Btu/yr):

(A) boilers with a rated heat input greater than or equal to 100 MMBtu/hr; and

(B) process heaters with a rated heat input greater than or equal to 100 MMBtu/hr, except as provided in subsection (g) of this section.

(2) The following are not subject to this subsection:

(A) units listed in §117.303(b)(3) - (5) and (8) - (10) of this title;

(B) process heaters operating with a carbon dioxide CEMS for diluent monitoring under subsection (g) of this section; and

(C) wood-fired boilers.

(3) The O_2 monitors required by this subsection are for process monitoring (predictive monitoring inputs, boiler trim, or process control) and are only required to meet the location specifications and quality assurance procedures referenced in subsection (f) of this section if O_2 is the monitored diluent under that subsection. However, if new O_2 monitors are required as a result of this subsection, the criteria in subsection (f) of this section should be considered the appropriate guidance for the location and calibration of the monitors.

(c) NO_x monitors.

(1) The owner or operator of units listed in this paragraph shall install, calibrate, maintain, and operate a CEMS or predictive emissions monitoring system (PEMS) to monitor exhaust NO_x. The units are:

(A) boilers with a rated heat input greater than or equal to 250 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr;

(B) process heaters with a rated heat input greater than or equal to 200 MMBtu/hr and an annual heat input greater than $2.2(10^{11})$ Btu/yr;

(C) stationary gas turbines with an MW rating greater than or equal to 30 MW operated more than 850 hours per year;

(D) units that use a chemical reagent for reduction of NO_x;

(E) units that the owner or operator elects to comply with the NO_x emission specifications of §117.305 of this title using a pound per MMBtu (lb/MMBtu) limit on a 30-day rolling average;

(F) lime kilns and lightweight aggregate kilns;

(G) units with a rated heat input greater than or equal to 100 MMBtu/hr that are subject to §117.310(a) of this title; and

(H) fluid catalytic cracking units (including carbon monoxide (CO) boilers, CO furnaces, and catalyst regenerator vents). In addition, the owner or operator shall monitor the stack exhaust flow rate with a flow meter using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

(2) The following are not required to install CEMS or PEMS under this subsection:

(A) for purposes of §117.305 of this title, units listed §117.303(b)(3) - (5) and (8) - (10) of this title; and

(B) units subject to the NOx CEMS requirements of 40 CFR Part 75.

(3) The owner or operator shall use one of the following methods to provide substitute emissions compliance data during periods when the NOx monitor is off-line:

(A) if the NOx monitor is a CEMS:

(i) subject to 40 CFR Part 75, use the missing data procedures specified in 40 CFR Part 75, Subpart D (Missing Data Substitution Procedures); or

(ii) subject to 40 CFR Part 75, Appendix E, use the missing data procedures specified in 40 CFR Part 75, Appendix E, §2.5 (Missing Data Procedures);

(B) use 40 CFR Part 75, Appendix E monitoring in accordance with §117.1240(e) of this title (relating to Continuous Demonstration of Compliance);

(C) if the NOx monitor is a PEMS:

(i) use the methods specified in 40 CFR Part 75, Subpart D; or

(ii) use calculations in accordance with §117.8110(b) of this title (relating to Emission Monitoring System Requirements for Utility Electric Generation Sources); or

(D) use the maximum block one-hour emission rate as measured during the initial demonstration of compliance required in §117.335(f) of this title (relating to Initial Demonstration of Compliance); or

(E) use the following procedures:

(i) for NOx monitor downtime periods less than 24 consecutive hours, use the maximum block one-hour NOx emission rate, in lb/MMBtu, from the previous 24 operational hours of the unit;

(ii) for NOx monitor downtime periods equal to or greater than 24 consecutive hours, use the maximum block one-hour NOx emission rate, in lb/MMBtu, from the previous 720 operational hours of the unit; and

(iii) if the fuel flow or stack exhaust flow monitor required by subsection (a) of this section is off-line simultaneous with the NOx monitor downtime, the owner or operator shall use the maximum block one-hour NOx pound per hour emission rate for the substitute data under clause (i) or (ii) of this subparagraph in lieu of the lb/MMBtu emission rate.

(d) Ammonia monitoring requirements. The owner or operator of units that are subject to the ammonia emission specifications of §117.310(c)(2) of this title shall comply with the ammonia monitoring requirements of §117.8130 of this title (relating to Ammonia Monitoring).

(e) CO monitoring. The owner or operator shall monitor CO exhaust emissions from each unit listed in subsection (c)(1) of this section using one or more of the methods specified in §117.8120 of this title (relating to Carbon Monoxide (CO) Monitoring).

(f) CEMS requirements. The owner or operator of any CEMS used to meet a pollutant monitoring requirement of this section shall comply with the following.

(1) The CEMS must meet the requirements of §117.8100(a) of this title (relating to Emission Monitoring System Requirements for Industrial, Commercial, and Institutional Sources).

(2) For units subject to §117.310 of this title:

(A) all bypass stacks must be monitored, in order to quantify emissions directed through the bypass stack:

(i) if the CEMS is located upstream of the bypass stack, then:

(I) no effluent streams from other potential sources of NO_x emissions may be introduced between the CEMS and the bypass stack; and

(II) the owner or operator shall install, operate, and maintain a continuous monitoring system to automatically record the date, time, and duration of each event when the bypass stack is open; and

(ii) process knowledge and engineering calculations may be used to determine volumetric flow rate for purposes of calculating mass emissions for each event when the bypass stack is open, provided that:

(I) the maximum potential calculated flow rate is used for emission calculations; and

(II) the owner or operator maintains, and makes available upon request by the executive director, records of all process information and calculations used for this determination; and

(B) exhaust streams of units that vent to a common stack do not need to be analyzed separately.

(g) PEMS requirements. The owner or operator of any PEMS used to meet a pollutant monitoring requirement of this section shall comply with the following.

(1) The PEMS must predict the pollutant emissions in the units of the applicable emission specifications of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

(2) The PEMS must meet the requirements of §117.8100(b) of this title.

(h) Engine monitoring. The owner or operator of any stationary gas engine subject to §117.305 of this title that is not equipped with NO_x CEMS or PEMS shall stack test engine NO_x and CO emissions as specified in §117.8140(a) of this title (relating to Emission Monitoring for Engines). The owner or operator of any stationary internal combustion engine subject to §117.310 of this title that is not equipped with NO_x CEMS or PEMS shall stack test engine NO_x and CO emissions as specified in §117.8140(a) and (b) of this title.

(i) Monitoring for stationary gas turbines less than 30 MW. The owner or operator of any stationary gas turbine rated less than 30 MW using steam or water injection to comply with the emission specifications of §117.305 or §117.315 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT) and Alternative Plant-Wide Emission Specifications) shall either:

(1) install, calibrate, maintain, and operate a NO_x CEMS or PEMS in compliance with this section and monitor CO in compliance with subsection (e) of this section; or

(2) install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly fuel and steam or water consumption:

(A) the system must be accurate to within $\pm$ 5.0%;

(B) the steam-to-fuel or water-to-fuel ratio monitoring data must constitute the method for demonstrating continuous compliance with the applicable emission specification of §117.305 or §117.315 of this title; and

(C) steam or water injection control algorithms are subject to executive director approval.

(j) Run time meters. The owner or operator of any stationary gas turbine or stationary internal combustion engine claimed exempt using the exemption of §117.303(a)(6)(D), (a)(10), (a)(11), (b)(2) or (b)(9) of this title shall record the operating time with an elapsed run time meter. Any run time meter installed on or after October 1, 2001, must be non-resettable.

(k) Hydrogen (H_2) monitoring. The owner or operator claiming the H_2 multiplier of §117.305(b)(6) or §117.315(g)(4) or (h) of this title shall sample, analyze, and record every three hours the fuel gas composition to determine the volume percent H_2.

(1) The total H_2 volume flow in all gaseous fuel streams to the unit must be divided by the total gaseous volume flow to determine the volume percent of H_2 in the fuel supply to the unit.

(2) Fuel gas analysis must be tested according to American Society for Testing and Materials (ASTM) Method D1945-81 or ASTM Method D2650-83, or other methods that are demonstrated to the satisfaction of the executive director and the United States Environmental Protection Agency to be equivalent.

(3) A gaseous fuel stream containing 99% H_2 by volume or greater may use the following procedure to be exempted from the sampling and analysis requirements of this subsection.

(A) A fuel gas analysis must be performed initially using one of the test methods in this subsection to demonstrate that the gaseous fuel stream is 99% H_2 by volume or greater.

(B) The process flow diagram of the process unit that is the source of the H_2 must be supplied to the executive director to illustrate the source and supply of the hydrogen stream.

(C) The owner or operator shall certify that the gaseous fuel stream containing H_2 will continuously remain, as a minimum, at 99% H_2 by volume or greater during its use as a fuel to the combustion unit.

(l) Data used for compliance.

(1) After the initial demonstration of compliance required by §117.335 of this title, the methods required in this section must be used to determine compliance with the emission specifications of §117.305 of this title. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

(2) For units subject to §117.310(a) of this title, the methods required in this section must be used in conjunction with the requirements of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) to determine compliance. For enforcement purposes, the executive director may also use other commission compliance methods to determine whether the source is in compliance with applicable emission limitations.

(m) Enforcement of NOx RACT limits. If compliance with §117.305 of this title is selected, no unit subject to §117.305 of this title may be operated at an emission rate higher than that allowed by the emission specifications of §117.305 of this title. If compliance with §117.315 of this title is selected, no unit subject to §117.315 of this title may be operated at an emission rate higher than that approved by the executive director under §117.352(b) of this title (relating to Final Control Plan Procedures for Reasonably Available Control Technology).

(n) Loss of NOx RACT exemption. The owner or operator of any unit claimed exempt from the emission specifications of this division using the low annual capacity factor exemption of §117.303(b)(2) of this title shall notify the executive director within seven days if the Btu/yr or hour-per-year limit specified in §117.10 of this title (relating to Definitions), as appropriate, is exceeded.

(1) If the limit is exceeded, the exemption from the emission specifications of this division is permanently withdrawn.

(2) Within 90 days after loss of the exemption, the owner or operator shall submit a compliance plan detailing a plan to meet the applicable compliance limit as soon as possible, but no later than 24 months after exceeding the limit. The plan must include a schedule of increments of progress for the installation of the required control equipment.

(3) The schedule is subject to the review and approval of the executive director.

(o) Testing and operating requirements. The owner or operator of units that are subject to §117.310(a) of this title shall comply with the following.

(1) The owner or operator of units that are subject to §117.310(a) of this title shall test the units as specified in §117.335 of this title in accordance with the schedule specified in §117.9020(2) of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

(2) Each stationary internal combustion engine controlled with nonselective catalytic reduction must be equipped with an automatic air-fuel ratio (AFR) controller that operates on exhaust O_2 or CO control and maintains AFR in the range required to meet the engine's applicable emission limits.

(p) Emission allowances. The owner or operator of units that are subject to §117.310(a) of this title shall comply with the following.

(1) The NO_x testing and monitoring data of subsections (a), (c), (f), (g), and (o) of this section, together with the level of activity, as defined in §101.350 of this title (relating to Definitions), must be used to establish the emission factor for calculating actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program.

(2) For units not operating with CEMS or PEMS, the following apply.

(A) Retesting as specified in subsection (o)(1) of this section is required within 60 days after any modification that could reasonably be expected to increase the NOx emission rate.

(B) Retesting as specified in subsection (o)(1) of this section may be conducted at the discretion of the owner or operator after any modification that could reasonably be expected to decrease the NOx emission rate, including, but not limited to, installation of post-combustion controls, low-NOx burners, low excess air operation, staged combustion (for example, overfire air), flue gas recirculation, and fuel-lean and conventional (fuel-rich) reburn.

(C) The NOx emission rate determined by the retesting must be used to establish a new emission factor to calculate actual emissions from the date of the retesting forward. Until the date of the retesting, the previously determined emission factor must be used to calculate actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

(D) All test reports must be submitted to the executive director for review and approval within 60 days after completion of the testing.

(3) The emission factor in paragraph (1) or (2) of this subsection is multiplied by the unit's level of activity to determine the unit's actual emissions for compliance with Chapter 101, Subchapter H, Division 3 of this title.

§117.345. Notification, Recordkeeping, and Reporting Requirements.

(a) Startup and shutdown records. For units subject to the startup and/or shutdown provisions of §101.222 of this title (relating to Demonstrations), hourly records must be made of startup and/or shutdown events and maintained for a period of at least two years. Records must be available for inspection by the executive director, the United States Environmental Protection Agency, and any local air pollution control agency having jurisdiction upon request. These records must include, but are not limited to: type of fuel burned; quantity of each type of fuel burned; and the date, time, and duration of the procedure.

(b) Notification. The owner or operator of an affected source shall submit notification to the appropriate regional office and any local air pollution control agency having jurisdiction as follows:

(1) verbal notification of the date of any testing conducted under §117.335 of this title (relating to Initial Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed; and

(2) verbal notification of the date of any continuous emissions monitoring system (CEMS) or predictive emissions monitoring system (PEMS) relative accuracy test audit (RATA) conducted under §117.340 of this title (relating to Continuous Demonstration of Compliance) at least 15 days prior to such date followed by written notification within 15 days after testing is completed.

(c) Reporting of test results. The owner or operator of an affected unit shall furnish the Office of Compliance and Enforcement, the appropriate regional office, and any local air pollution control agency having jurisdiction a copy of any testing conducted under §117.335 of this title and any CEMS or PEMS RATA conducted under §117.340 of this title:

(1) within 60 days after completion of such testing or evaluation; and

(2) not later than the compliance schedule specified in §117.9020 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

(d) Semiannual reports. The owner or operator of a unit required to install a CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system under §117.340 of this title shall report in writing to the executive director on a semiannual basis any exceedance of the applicable emission specifications of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources) and the monitoring system performance. For sources in the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program), that are no longer subject to §117.305 of this title (relating to Emission

Specifications for Reasonably Available Control Technology (RACT)), the report is only a monitoring system report as specified in paragraph (3) of this subsection. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports must include the following information:

(1) the magnitude of excess emissions computed in accordance with 40 Code of Federal Regulations §60.13(h), any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the unit operating time during the reporting period:

(A) for stationary gas turbines using steam-to-fuel or water-to-fuel ratio monitoring to demonstrate compliance in accordance with §117.340(i)(2) of this title, excess emissions are computed as each one-hour period that the average steam or water injection rate is below the level defined by the control algorithm as necessary to achieve compliance with the applicable emission specifications in §117.305 of this title; and

(B) for units complying with §117.323 of this title (relating to Source Cap), excess emissions are each daily period that the total nitrogen oxides (NO_x) emissions exceed the rolling 30-day average or the maximum daily NO_x cap;

(2) specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted;

(3) the date and time identifying each period that the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments;

(4) when no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information must be stated in the report; and

(5) if the total duration of excess emissions for the reporting period is less than 1.0% of the total unit operating time for the reporting period and the CEMS, PEMS, or water-to-fuel or steam-

to-fuel ratio monitoring system downtime for the reporting period is less than 5.0% of the total unit operating time for the reporting period, only a summary report form (as outlined in the latest edition of the commission's *Guidance for Preparation of Summary, Excess Emission, and Continuous Monitoring System Reports*) must be submitted, unless otherwise requested by the executive director. If the total duration of excess emissions for the reporting period is greater than or equal to 1.0% of the total operating time for the reporting period or the CEMS, PEMS, or water-to-fuel or steam-to-fuel ratio monitoring system downtime for the reporting period is greater than or equal to 5.0% of the total operating time for the reporting period, a summary report and an excess emission report must both be submitted.

(e) Reporting for engines. The owner or operator of any gas-fired engine subject to §§117.305, 117.310, or 117.315 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT); Emission Specifications for Attainment Demonstration; and Alternative Plant-Wide Emission Specifications) shall report in writing to the executive director on a semiannual basis any excess emissions and the air-fuel ratio monitoring system performance. All reports must be postmarked or received by the 30th day following the end of each calendar semiannual period. Written reports must include the following information:

(1) the magnitude of excess emissions (based on the quarterly emission checks of §117.330(d)(7) of this title (relating to Operating Requirements) and the biennial emission testing required for demonstration of emissions compliance in accordance with §117.340(h) of this title, computed in pounds per hour and grams per horsepower-hour, any conversion factors used, the date and time of commencement and completion of each time period of excess emissions, and the engine operating time during the reporting period; and

(2) specific identification, to the extent feasible, of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the engine or emission control system, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(f) Recordkeeping. The owner or operator of a unit subject to the requirements of this division shall maintain written or electronic records of the data specified in this subsection. Such records must be kept for a period of at least five years and must be made available upon request by authorized representatives of the executive director, the United States Environmental Protection Agency, or local air pollution control agencies having jurisdiction. The records must include:

(1) for each unit subject to §117.340(a) of this title, records of annual fuel usage;

(2) for each unit using a CEMS or PEMS in accordance with §117.340 of this title, monitoring records of:

(A) hourly emissions and fuel usage (or stack exhaust flow) for units complying with an emission limit enforced on a block one-hour average;

(B) daily emissions and fuel usage (or stack exhaust flow) for units complying with an emission limit enforced on a daily or rolling 30-day average. Emissions must be recorded in units of:

(i) pound per million British thermal units (lb/MMBtu) heat input; and

(ii) pounds or tons per day; or

(C) daily emissions and fuel usage (or stack exhaust flow) for units subject to the mass emissions cap and trade program of Chapter 101, Subchapter H, Division 3 of this title. Emissions must be recorded in units of:

(i) lb/MMBtu heat input or in the units of the applicable emission specification in §117.310(a) of this title; and

(ii) pounds or tons per day;

(3) for each stationary internal combustion engine subject to the emission specifications of this division, records of:

(A) emissions measurements required by:

(i) §117.330(d)(7) of this title; and

(ii) §117.340(h) of this title; and

(B) catalytic converter, air-fuel ratio controller, or other emissions-related control system maintenance, including the date and nature of corrective actions taken;

(4) for each stationary gas turbine monitored by steam-to-fuel or water-to-fuel ratio in accordance with §117.340(i) of this title, records of hourly:

(A) pounds of steam or water injected;

(B) pounds of fuel consumed; and

(C) the steam-to-fuel or water-to-fuel ratio;

(5) for hydrogen (H_2) fuel monitoring in accordance with §117.340(k) of this title, records of the volume percent H_2 every three hours;

(6) for units claimed exempt from emission specifications using the exemption of §117.303(a)(6)(D), (a)(10), (a)(11), or (b)(2) of this title (relating to Exemptions), either records of monthly:

(A) fuel usage, for exemptions based on heat input; or

(B) hours of operation, for exemptions based on hours per year of operation. In addition, for each engine claimed exempt under §117.303(a)(6)(D) of this title, written records must be maintained of the purpose of engine operation and, if operation was for an emergency situation, identification of the type of emergency situation and the start and end times and date(s) of the emergency situation;

(7) records of carbon monoxide measurements specified in §117.340(e) of this title;

(8) records of the results of initial certification testing, evaluations, calibrations, checks, adjustments, and maintenance of CEMS, PEMS, or steam-to-fuel or water-to-fuel ratio monitoring systems;

(9) records of the results of performance testing, including initial demonstration of compliance testing conducted in accordance with §117.335 of this title;

(10) for each stationary diesel or dual-fuel engine, records of each time the engine is operated for testing and maintenance, including:

(A) date(s) of operation;

(B) start and end times of operation;

(C) identification of the engine; and

(D) total hours of operation for each month and for the most recent 12 consecutive months; and

(11) for units subject to the ammonia monitoring requirements of §117.340(d) of this title, records that are sufficient to demonstrate compliance with the requirements of §117.8130 of this title (relating to Ammonia Monitoring). For the sorbent or stain tube option, these records must include the ammonia injection rate and NOx stack emissions measured during each sorbent or stain tube test.

§117.350. Initial Control Plan Procedures.

(a) The owner or operator of any major source of nitrogen oxides (NOx) shall submit, for the approval of the executive director, an initial control plan for installation of NOx emissions control equipment (if required in order to comply with the emission specifications of this subchapter) and demonstration of anticipated compliance with the applicable requirements of this subchapter.

(1) This section applies only to sources that were major for NOx emissions before November 15, 1992.

(2) The executive director shall approve the plan if it contains all the information specified in this section.

(3) Revisions to the initial control plan must be submitted with the final control plan.

(b) The owner or operator shall provide results of emissions testing using portable or reference method analyzers or, as available, initial demonstration of compliance testing conducted in accordance with §117.335(e) or (f) of this title (relating to Initial Demonstration of Compliance) for NOx, carbon monoxide (CO), and oxygen emissions while firing gaseous fuel (and as applicable, hydrogen (H_2) fuel for units that may fire more than 50% H_2 by volume) and liquid and/or solid fuel at the maximum rated capacity or as near thereto as practicable, for the units listed in this subsection. Previous testing documentation for any claimed test waiver as allowed by §117.335(d) of this title must be submitted with the initial control plan. Any units that were not operated between June 9, 1993, and April 1, 1994, and do not have earlier representative emission test results available, must be tested and the results submitted to the executive director, with certification of the equipment's shutdown period, within 90 days after the date such equipment is returned to operation. Test results are required for the following units:

(1) boilers and process heaters with a maximum rated capacity greater than or equal to 40 million British thermal units per hour (MMBtu/hr), except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title (relating to Definitions);

(2) boilers and industrial furnaces with a maximum rated capacity greater than or equal to 40 MMBtu/hr that were regulated as existing facilities by 40 Code of Federal Regulations, Part 266, Subpart H, as was in effect on June 9, 1993, except for low annual capacity factor boilers and process heaters as defined in §117.10 of this title;

(3) fluid catalytic cracking units with a maximum rated capacity greater than or equal to 40 MMBtu/hr;

(4) gas turbine supplemental waste heat recovery units with a maximum rated fired capacity greater than or equal to 40 MMBtu/hr, except for low annual capacity factor gas turbine supplemental waste heat recovery units as defined in §117.10 of this title;

(5) stationary gas turbines with a megawatt (MW) rating of greater than or equal to 1.0 MW, except for low annual capacity factor gas turbines or peaking gas turbines as defined in §117.10 of this title; and

(6) gas-fired, stationary, reciprocating internal combustion engines rated 150 horsepower (hp) or greater, except for low annual capacity factor engines or peaking engines as defined in §117.10 of this title.

(c) The initial control plan must be submitted by April 1, 1994, and must contain the following:

(1) a list of all combustion units at the source with a maximum rated capacity greater than 5.0 MMBtu/hr; all stationary, reciprocating internal combustion engines rated 150 hp or greater; all stationary gas turbines with an MW rating of greater than or equal to 1.0 MW; the maximum rated capacity, anticipated annual capacity factor, the facility identification numbers and emission point numbers as submitted to the Industrial Emissions Assessment Section of the commission; and the emission point numbers as listed on the Maximum Allowable Emissions Rate Table of any applicable commission permit for each unit;

(2) identification of all units subject to the emission specifications of §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.315 of this title (relating to Alternative Plant-Wide Emission Specifications), or §117.323 of this title (relating to Source Cap);

(3) identification of all boilers, process heaters, stationary gas turbines, or engines with a claimed exemption from the emission specifications of §117.305 or §117.315 of this title and the rule basis for the claimed exemption;

(4) identification of the election to use individual emission limits as specified in §117.305 of this title, the plant-wide emission specification as specified in §117.315 of this title, or the source cap emission limit as specified in §117.323 of this title to achieve compliance with this rule;

(5) a list of units to be controlled and the type of control to be applied for all such units, including an anticipated construction schedule;

(6) a list of units requiring operating modifications to comply with §117.330(d) of this title (relating to Operating Requirements) and the type of modification to be applied for all such units, including an anticipated construction schedule;

(7) a list of any units that have been or will be retired, decommissioned, or shutdown and rendered inoperable after November 15, 1990, as a result of compliance with §117.305 of this title, indicating the date of occurrence or anticipated date of occurrence;

(8) the basis for calculation of the rate of NO_x emissions for each unit to demonstrate that each unit will achieve the NO_x emission rates specified in this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources). For fluid catalytic cracking unit CO boilers, the basis for calculation of the NO_x emission rate in pounds per million British thermal units (lb/MMBtu) for each unit must include the following:

(A) the calculation of the CO boiler heat input;

(B) the calculation of the appropriate CO boiler volumetric inlet and exhaust flowrates; and

(C) the calculation of the CO boiler NO_x emission rate in lb/MMBtu;

(9) for units required to install totalizing fuel flow meters in accordance with §117.340(a) of this title (relating to Continuous Demonstration of Compliance), indication of whether the devices are currently in operation, and if so, whether they have been installed as a result of the requirements of this chapter;

(10) for units that have had NOx reduction projects as specified in §117.305(a)(1)(B) of this title, documentation that such projects were undertaken solely for the purpose of obtaining early NOx reductions; and

(11) test results in accordance with subsection (b) of this section.

§117.352. Final Control Plan Procedures for Reasonably Available Control Technology.

(a) The owner or operator of units listed in §117.300 of this title (relating to Applicability) at a major source of nitrogen oxides (NOx) shall submit a final control report to show compliance with the requirements of §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)). The report must include a list of the units listed in §117.300 of this title, showing:

(1) the NOx emission specification resulting from application of §117.305 of this title for each non-exempt unit;

(2) the section under which NOx compliance is being established for units specified in paragraph (1) of this subsection, either:

(A) §117.305 of this title;

(B) §117.315 of this title (relating to Alternative Plant-Wide Emission Specifications);

(C) §117.323 of this title (relating to Source Cap);

(D) §117.325 of this title (relating to Alternative Case Specific Specifications); or

(E) §117.9800 of this title (relating to Use of Emission Credits for Compliance);

(3) the method of NOx control for each unit;

(4) the emissions measured by testing required in §117.335 of this title (relating to Initial Demonstration of Compliance);

(5) the submittal date, and whether sent to the Austin or the regional office (or both), of any compliance stack test report or relative accuracy test audit report required by §117.335 of this title that is not being submitted concurrently with the final compliance report; and

(6) the specific rule citation for any unit with a claimed exemption from the emission specifications of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources), for:

(A) boilers and heaters with a maximum rated capacity greater than or equal to 100.0 million British thermal units per hour;

(B) gas turbines with a megawatt (MW) rating greater than or equal to 10.0 MW; and

(C) gas-fired internal combustion engines rated greater than or equal to 150 horsepower.

(b) For sources complying with §117.315 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall:

(1) assign to each affected:

(A) boiler or process heater, the maximum allowable NOx emission rate in pounds per million British thermal units (rolling 30-day average), or in pounds per hour (block one-hour average) indicating whether the fuel is gas, high-hydrogen gas, solid, or liquid;

(B) stationary gas turbine, the maximum allowable NOx emission in parts per million by volume at 15% oxygen, dry basis on a block one-hour average; and

(C) stationary internal combustion engine, the maximum allowable NOx emission rate in grams per horsepower-hour on a block one-hour average;

(2) submit a list to the executive director for approval of:

(A) the maximum allowable NOx emission rates identified in paragraph (1) of this subsection; and

(B) the maximum rated capacity for each unit;

(3) submit calculations used to calculate the plant-wide average in accordance with §117.315(g) of this title; and

(4) maintain a copy of the approved list of emission specifications for verification of continued compliance with the requirements of §117.315 of this title.

(c) For sources complying with §117.323 of this title, in addition to the requirements of subsection (a) of this section, the owner or operator shall submit:

(1) the calculations used to calculate the 30-day average and maximum daily source cap allowable emission rates; and

(2) a list containing, for each unit in the cap:

(A) the historical average daily heat input information, H_i;

(B) the maximum daily heat input, H_{mi};

(C) the applicable restriction, R_i; and

(D) the method of monitoring emissions;

(3) an explanation of the basis of the values of H_i, H_{mi}, and R_i; and

(4) the information applicable to shutdown units, specified in §117.323(g) of this title.

(d) The report must be submitted by the applicable date specified for final control plans in §117.9020 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with an emission limit on a rolling 30-day average, according to the applicable schedule given in §117.9020 of this title.

§117.354. Final Control Plan Procedures for Attainment Demonstration Emission Specifications.

(a) The owner or operator of units listed in §117.310(a) of this title (relating to Emission Specifications for Attainment Demonstration) at a major source of nitrogen oxides (NO_x) shall submit a final control report to show compliance with the requirements of §117.310 of this title. The report must include:

(1) the section under which NOx compliance is being established, either:

(A) Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program); and, where applicable, §117.320 of this title (relating to System Cap); or

(B) §117.9800 of this title (relating to Use of Emission Credits for Compliance);

(2) the method of NO_x control for each unit;

(3) the emissions measured by testing required in §117.335 of this title (relating to Initial Demonstration of Compliance);

(4) the submittal date, and whether sent to the central or the regional office (or both), of any compliance stack test report or relative accuracy test audit report required by §117.335 of this title that is not being submitted concurrently with the final compliance report;

(5) the specific rule citation for any unit with a claimed exemption from §117.310 of this title; and

(6) for sources complying with §117.320 of this title, in addition to the requirements of paragraphs (1) - (5) of this subsection, the owner or operator shall submit:

(A) the calculations used to calculate the 30-day average and maximum daily system cap allowable emission rates;

(B) a list containing, for each unit in the cap:

(i) the average daily heat input, H_i, specified in §117.320(c)(1) and (2) of this title;

(ii) the maximum daily heat input, H_{mi}, specified in §117.320(c)(3) of this title;

(iii) the method of monitoring emissions; and

(iv) the method of providing substitute emissions data when the NOx monitoring system is not providing valid data; and

(C) an explanation of the basis of the values of H_i and H_{mi}.

(b) The report must be submitted to the executive director by the applicable date specified for final control plans in §117.9020 of this title (relating to Compliance Schedule for Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources). The plan must be updated with any emission compliance measurements submitted for units using continuous emissions monitoring system or predictive emissions monitoring system and complying with the system cap rolling 30-day average emission limit, according to the applicable schedule given in §117.9020 of this title.

§117.356. Revision of Final Control Plan.

A revised final control plan may be submitted by the owner or operator, along with any required permit applications. Such a plan must adhere to the requirements and the final compliance dates of this division (relating to Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources).

(1) For sources complying with §117.305 of this title (relating to Emission Specifications for Reasonably Available Control Technology (RACT)), §117.310 of this title (relating to Emission Specifications for Attainment Demonstration), or §117.315 of this title (relating to Alternative Plant-Wide Emission Specifications), replacement new units may be included in the control plan.

(2) For sources complying with §117.323 of this title (relating to Source Cap), any new unit must be included in the source cap, if the unit belongs to an equipment category that is included in the source cap.

(3) The revision of the final control plan must be subject to the review and approval of the executive director.